APPENDIX E

APPLICANT'S ENVIRONMENTAL REPORT – OPERATING LICENSE RENEWAL STAGE

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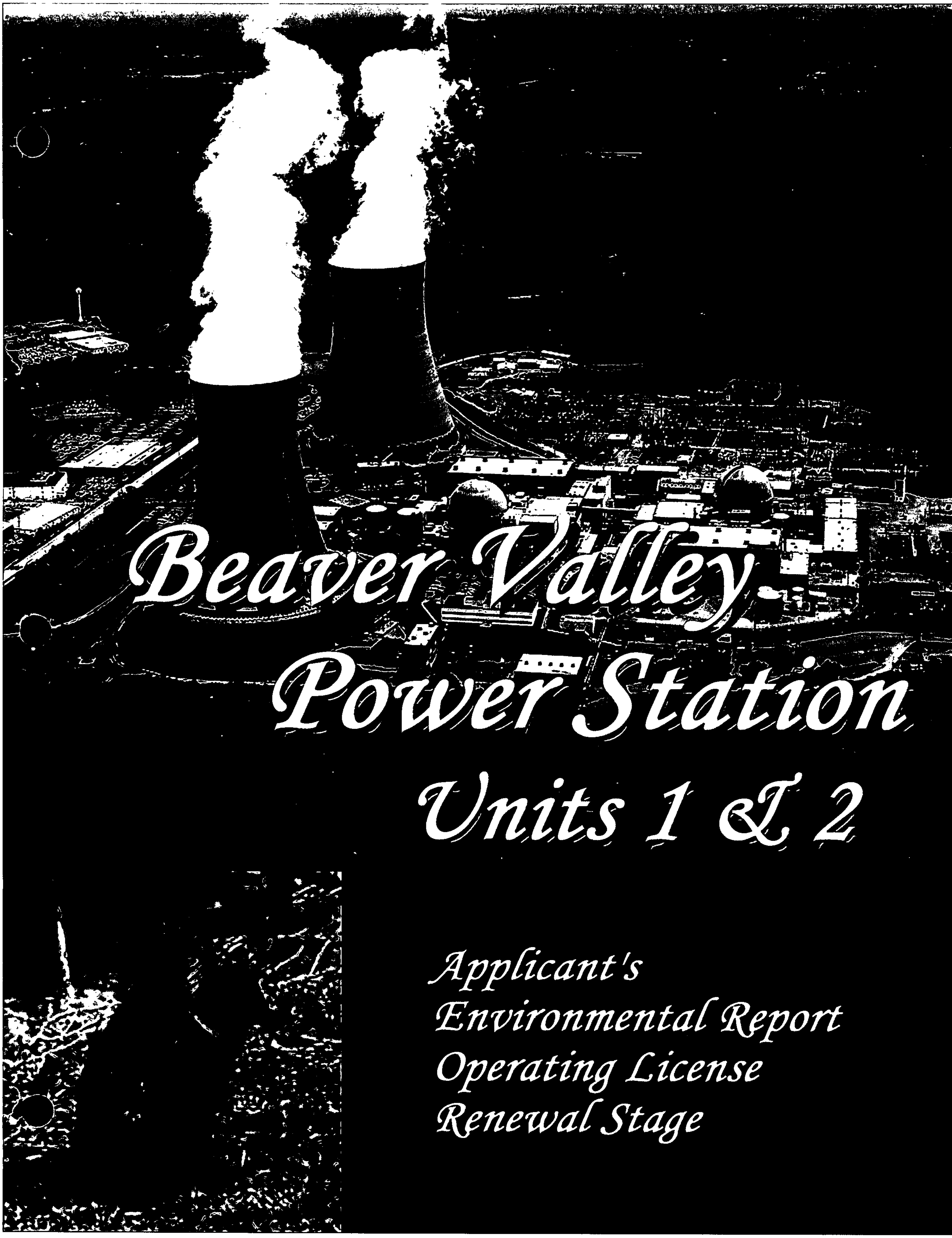

Beaver Valley Power Station Units 1 & 2

Applicant's Environmental Report Operating License Renewal Stage

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Applicant's Environmental Report – Operating License Renewal Stage

Beaver Valley Power Station Units 1 and 2

Unit 1
Docket No. 50-334
License No. DPR-66

Unit 2
Docket No. 50-412
License No. NPF-73

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ACRONYMS AND ABBREVIATIONS

>	greater than
<	less than
%	percent
7Q10	once-in-10-year, 7-day duration low flow
°F	degrees Fahrenheit
AADT	average annual daily traffic volume
AC	alternating current
AEC	U.S. Atomic Energy Commission
AFW	Auxiliary Feedwater
ARP	Alarm Response Procedure
ATSI	American Transmission Systems, Inc.
ATWS	Anticipated Transients Without Scram
BACT	best available control technology
Btu	British thermal unit(s)
BVPS	Beaver Valley Power Station
CAPCO	Central Area Power Coordinating Group
CCW	component cooling water
CDF	core damage frequency
CEQ	Council on Environmental Quality
CET	Containment Event Tree
CFR	*Code of Federal Regulations*
cfs	cubic feet per second
CNS	Constellation Nuclear Services, Inc.
CO	carbon monoxide
CO_2	carbon dioxide
CT	combustion turbine
CWA	(Federal) Clean Water Act
DBA	Design Basis Accident
DC	Direct Current
DLC	Duquesne Light Company
DOE-EIA	U.S. Department of Energy, Energy Information Agency

ACRONYMS AND ABBREVIATIONS (CONTINUED)

DSM	demand side management
EA	EA Engineering, Science, and Technology
ECAR	East Central Area Reliability Coordination Agreement
ECCS	Emergency Component Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ER	environmental report
ERF	emergency response facility
FBC	fluidized bed combustion
FENOC	FirstEnergy Nuclear Operating Company
FERC	Federal Energy Regulatory Commission
FES	Final Environmental Statement
ft	foot
FV	Fussel Vessely
FWS	U.S. Fish and Wildlife Service
GEIS	*Generic Environmental Impact Statement for License Renewal of Nuclear Plants*
g	gravity
gpd	gallons per day
gpm	gallons per minute
GWD/MTU	gigawatt-days per metric ton of uranium
GWh	gigawatt-hour(s)
HCLPF	high confidence, low probability of failure
HHSI	High Head Safety Integration
HRSG	heat recovery steam generator
HVAC	Heating, Ventilation, and Air Conditioning
IGCC	integrated gasification combined cycle
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination for External Events
ISLOCA	Interfacing System Loss of Coolant Accident

ACRONYMS AND ABBREVIATIONS (CONTINUED)

ISO	independent system operator
kV	kilovolt
kV/m	kilovolts per meter
kWh	kilowatt-hour(s)
LAER	lowest achievable emission rate
lb	pound
LERF	large early release frequency
LHSI	low head safety integration
LOCA	Loss of Coolant Accident
LOSP	Loss of Offsite Power
LRA	license renewal application
m	meter(s)
mA	milliamperes
MAAC	Mid-Atlantic Area Council
MACCS2	Melcor Accident Consequences Code System Version 2
MFW	Main Feedwater
mgd	million gallons per day
MMBtu	million British thermal unit(s)
MOV	Motor-Operated Valve
MSA	metropolitan statistical area
MSSV	main steam safety valve
MW	megawatt(s)
MWe	megawatt-electric
MWt	megawatt-thermal
NA	not applicable
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NESC®	National Electrical Safety Code®
NGVD	National Geodetic Vertical Datum
NOAA	National Oceanic and Atmospheric Administration
NO_x	nitrogen oxides

ACRONYMS AND ABBREVIATIONS (CONTINUED)

NPDES	National Pollutant Discharge Elimination System
NPSH	Net Positive Suction Head
NRC	U.S. Nuclear Regulatory Commission
OAC	Ohio Administrative Code
ODNR	Ohio Department of Natural Resources
OH	Ohio
OPSB	Ohio Power Siting Board
ORSANCO	Ohio River Valley Water Sanitation Commission
PA	Pennsylvania
PADEP	Pennsylvania Department of Environmental Protection
PBHP	Pennsylvania Bureau for Historic Preservation
PCB	polychlorinated biphenyl
PDCNR	Pennsylvania Department of Conservation and Natural Resources
PFBC	Pennsylvania Fish and Boat Commission
PJM	PJM Interconnection, LLC
PM	filterable particulate matter
PM_{10}	filterable particulates with diameter less than 10 microns
PNDI	Pennsylvania Natural Diversity Inventory
PORV	Power-Operated Relief Valve
PRA	Probabilistic Risk Assessment
psig	pounds per square inch gauge
PSV	Pressurizer Safety Valve
PURTA	Public Utility Realty Tax Act
PWR	pressurized water reactor
QS	Quench Spray
RBC	rotating biological contactor
RCS	reactor coolant system
Ref.	Reference
RHR	residual heat removal
RIMS II	Regional Input-Output Modeling System
ROW	right-of-way

ACRONYMS AND ABBREVIATIONS (CONTINUED)

RPS	renewable portfolio standard
RRW	Risk Reduction Worth
RTO	regional transmission operator
RWST	Refueling Water Storage Tank
SAMA	Severe Accident Mitigation Alternatives
SAPS	Shippingport Atomic Power Station
SBO	Station Blackout
scf	standard cubic feet
SERF	small early release frequency
SG	steam generator
SGTR	Steam Generator Tube Rupture
SHPO	State Historic Preservation Office(r)
SI	Safety Injection
SMITTR	surveillance, on-line monitoring, inspections, testing, trending, and recordkeeping
SO_2	sulfur dioxide
SO_x	sulfur oxides
SR	State Route
SSPS	Solid State Protection System
ST	steam turbine
TDAFW	turbine driven auxiliary feedwater
UFSAR	Updated Final Safety Analysis Report
USACE	U.S. Army Corps of Engineers
USC	United States Code
USGS	U.S. Geological Survey
wt%	percent by weight
WV	West Virginia
WVDNR	West Virginia Division of Natural Resources
yr	year

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1.0 PURPOSE OF AND NEED FOR ACTION

1.1 INTRODUCTION AND BACKGROUND

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants in accordance with the Atomic Energy Act of 1954, as amended, and NRC implementing regulations. FirstEnergy Nuclear Operating Company (FENOC) is licensed to operate the Beaver Valley Power Station (BVPS) Units 1 and 2, pursuant to NRC Operating Licenses DPR-66 and NPF-73, respectively. The license for BVPS-1 will expire January 29, 2016, and the license for BVPS-2 will expire May 27, 2027 (Ref. 1.1-1; Ref. 1.1-2). FENOC is seeking to renew each of these licenses for an additional twenty-year term and has prepared this environmental report (ER) in connection with the BVPS license renewal application, as provided by the following NRC regulations:

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

1.2 STATEMENT OF PURPOSE AND NEED

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

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

The proposed action would provide FENOC the option to operate BVPS-1 and BVPS-2 for an additional 20 years.

1.3 ENVIRONMENTAL SCOPE AND METHODOLOGY

The NRC regulations for domestic licensing of nuclear power plants require environmental review of applications to renew operating licenses. NRC regulation 10 CFR 51.53(c) requires that an applicant for license renewal submit as part of its application, *Applicant's Environmental Report - Operating License Renewal Stage*. In determining what information to include in the BVPS ER, FENOC relied on NRC regulations and the following supporting documents, which provide additional insight into the regulatory requirements:

- NRC supplemental information in the *Federal Register* (FR) (Ref. 1.2-2; Ref. 1.3-1; Ref. 1.3-2; Ref. 1.3-3);
- GEIS (Ref. 1.2-1; Ref. 1.3-4);
- *Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses* (Ref. 1.3-5);
- *Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response* (Ref. 1.3-6).

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

- Supplement 1 to NRC Regulatory Guide 4.2, *Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses* (Ref. 1.3-7);
- Supplement 1 to NUREG-1555 *Standard Review Plans for Environmental Reviews for Nuclear Power Plants (Operating License Renewal)* (Ref. 1.3-8);
- Supplements 1 through 30 to NUREG-1437, GEIS (Ref. 1.3-9 through 1.3-38).

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

TABLE 1.3-1

ENVIRONMENTAL REPORT RESPONSES TO LICENSE RENEWAL ENVIRONMENTAL REGULATORY REQUIREMENTS

Regulatory Requirement	Responsive Environmental Report Section(s)	
10 CFR 51.53(c)(1)		Entire Document
10 CFR 51.53(c)(2), Sentences 1 and 2	3.0	The Proposed Action
10 CFR 51.53(c)(2), Sentence 3	7.3	Environmental Impacts of Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(1)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	6.3	Unavoidable Adverse Impacts
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	7.0	Alternatives to the Proposed Action
	8.0	Comparison of Environmental Impact of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(4)	6.5	Short-Term Use Versus Long-Term Productivity of the Environment
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(5)	6.4	Irreversible or Irretrievable Resource Commitments
10 CFR 51.53(c)(2) and 10 CFR 51.45(c)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
	6.2	Mitigation
	7.3	Environmental Impacts of Alternatives
	8.0	Comparison of Environmental Impact of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(d)	9.0	Status of Compliance
10 CFR 51.53(c)(2) and 10 CFR 51.45(e)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
	6.3	Unavoidable Adverse Impacts
10 CFR 51.53(c)(3)(ii)(A)	4.2	Water Use Conflicts (Plants Using Cooling Water Towers or Cooling Ponds and Withdrawing Makeup Water from a Small River)
	4.7	Groundwater Use Conflicts (Plants Using Cooling Water Towers or Cooling Ponds and Withdrawing Makeup Water from a Small River)
10 CFR 51.53(c)(3)(ii)(B)	4.3	Entrainment of Fish and Shellfish in Early Life Stages
	4.4	Impingement of Fish and Shellfish
	4.5	Heat Shock

TABLE 1.3-1 (CONTINUED)

ENVIRONMENTAL REPORT RESPONSES TO LICENSE RENEWAL ENVIRONMENTAL REGULATORY REQUIREMENTS

Regulatory Requirement	Responsive Environmental Report Section(s)	
10 CFR 51.53(c)(3)(ii)(C)	4.6	Groundwater Use Conflicts (Plants Using >100 gpm of Groundwater)
	4.8	Groundwater Use Conflicts (Plants Using Ranney Wells)
10 CFR 51.53(c)(3)(ii)(D)	4.9	Degradation of Groundwater Quality
10 CFR 51.53(c)(3)(ii)(E)	4.10	Impacts of Refurbishment on Terrestrial Resources
	4.11	Threatened or Endangered Species
10 CFR 51.53(c)(3)(ii)(F)	4.12	Air Quality During Refurbishment (Nonattainment Areas)
10 CFR 51.53(c)(3)(ii)(G)	4.13	Impact on Public Health of Microbiological Organisms
10 CFR 51.53(c)(3)(ii)(H)	4.14	Electric Shock from Transmission Line-Induced Currents
10 CFR 51.53(c)(3)(ii)(I)	4.15	Housing Impacts
	4.16	Public Water Supply Availability
	4.17	Education Impacts from Refurbishment
	4.18	Offsite Land Use
10 CFR 51.53(c)(3)(ii)(J)	4.19	Transportation
10 CFR 51.53(c)(3)(ii)(K)	4.20	Historic and Archeological Resources
10 CFR 51.53(c)(3)(ii)(L)	4.21	Severe Accident Mitigation Alternatives
10 CFR 51.53(c)(3)(iii)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
	6.2	Mitigation
10 CFR 51.53(c)(3)(iv)	5.0	Assessment of New and Significant Information
10 CFR 51, Appendix B to Subpart A, Table B-1, Footnote 6	2.5.2	Minority and Low-Income Populations

CFR = *Code of Federal Regulations*

gpm = gallons per minute

> = greater than

1.4 REFERENCES

Note to reader: This list of references identifies web pages and associated URLs where reference data was obtained. Some of these web pages may likely no longer be available or their URL addresses may have changed. FENOC has maintained hard copies of the information and data obtained from the referenced web pages.

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2.0 SITE AND ENVIRONMENTAL INTERFACES

2.1 LOCATION AND FEATURES

BVPS is located on the south bank of the Ohio River at approximate river mile 34.8 in Shippingport Borough, Beaver County, Pennsylvania. The two-unit station lies approximately 25 miles northwest of Pittsburgh, Pennsylvania; approximately 1 mile southeast of Midland, Pennsylvania; 7 miles east of East Liverpool, Ohio; 8 miles east of Newell, West Virginia; and 8 miles southwest of Beaver, Pennsylvania. The coordinates for the site are latitude 40.6219°N and longitude 80.4339°W (Ref. 2.1-22, page A-6).

The entire site consists of approximately 453 acres, about 48 acres less than the 501 acres reported in the BVPS-2 "Final Environmental Statement" (FES) (Ref. 2.1-17, Section 4.2.2), primarily as a result of the sale of a 46 acre tract south of State Route (SR) 168 to Freeport Development Corporation (now Laurel Ventures) in 1995 (Ref. 2.1-4, Section 2.1) and survey adjustments. The region (approximately 50 miles in radius) and the BVPS site vicinity (approximately 6 miles in radius) are illustrated in Figures 2.1-1 and 2.1-2, respectively. Figure 2.1-3 shows the BVPS site and its immediate environs. General features in the site vicinity have undergone relatively little change since the mid-1980s, when BVPS-2 began operation.

2.1.1 Regional Features

BVPS is located within the Pittsburgh Low Plateau Section of the Appalachian Plateau Physiographic Province, which is characterized by a smooth, undulating, upland surface cut by numerous narrow, relatively shallow river valleys (Ref. 2.1-1). Upland areas have been altered over time by strip mining, stream erosion, and glacially induced erosion. Local relief on the uplands is generally less than 200 feet, with differences of as much as 600 feet between valley bottoms and upland surfaces. Valley sides are usually moderately steep except in the upper reaches of streams where the side slopes are fairly gentle. Elevations range from 660 to 1,700 feet (Ref. 2.1-1). The BVPS site region encompasses portions of Pennsylvania, Ohio, and West Virginia.

The major river systems in the region consist of the Monongahela, Allegheny, and Ohio Rivers, and their tributaries. The Monongahela and Allegheny Rivers originate in north-central West Virginia and in southwestern New York, respectively. The Ohio River is formed by the confluence of the Monongahela and Allegheny Rivers at Pittsburgh, and extends 981 river miles to Cairo, Illinois, where it joins the Mississippi River (Ref. 2.1-2). The Ohio River and lower portions of the Allegheny and Monongahela Rivers are maintained and controlled by a series of locks and dams operated by the U.S. Army Corps of Engineers (USACE). The USACE Pittsburgh District operates six locks and dams on the upper Ohio River, eight locks and dams on the lower Allegheny River, and nine locks and dams on the lower Monongahela River (Ref. 2.1-3). Commercial use of the Ohio River for transportation has increased over the years, amounting to approximately 150 million tons of cargo shipped annually (Ref. 2.1-2). Montgomery and New Cumberland Locks average about 1100 commercial lockages each month (Ref. 2.1-3). The major state and interstate highways connecting major municipal areas in the region are shown on Figure 2.1-1. Rail is also a predominant form of transportation for materials and cargo. Because the railroads need level and continuous corridors, rail lines in the area essentially follow the same courses as the rivers and streams (Ref. 2.1-4, Section 2.1).

Pittsburgh is the largest city within 50 miles of BVPS and is the center for industrial activity in the region. The combination of available raw materials, product markets, the Ohio River, and transportation facilities led to the development of the region as a major industrial center; manufacturing of iron and steel has been particularly important to the region's economy. The presence of mineral resources—including coal, clay, gas, oil, sand, and gravel—are also regionally important (Ref. 2.1-4, Section 2.1).

FIGURE 2.1-1

50-MILE REGION

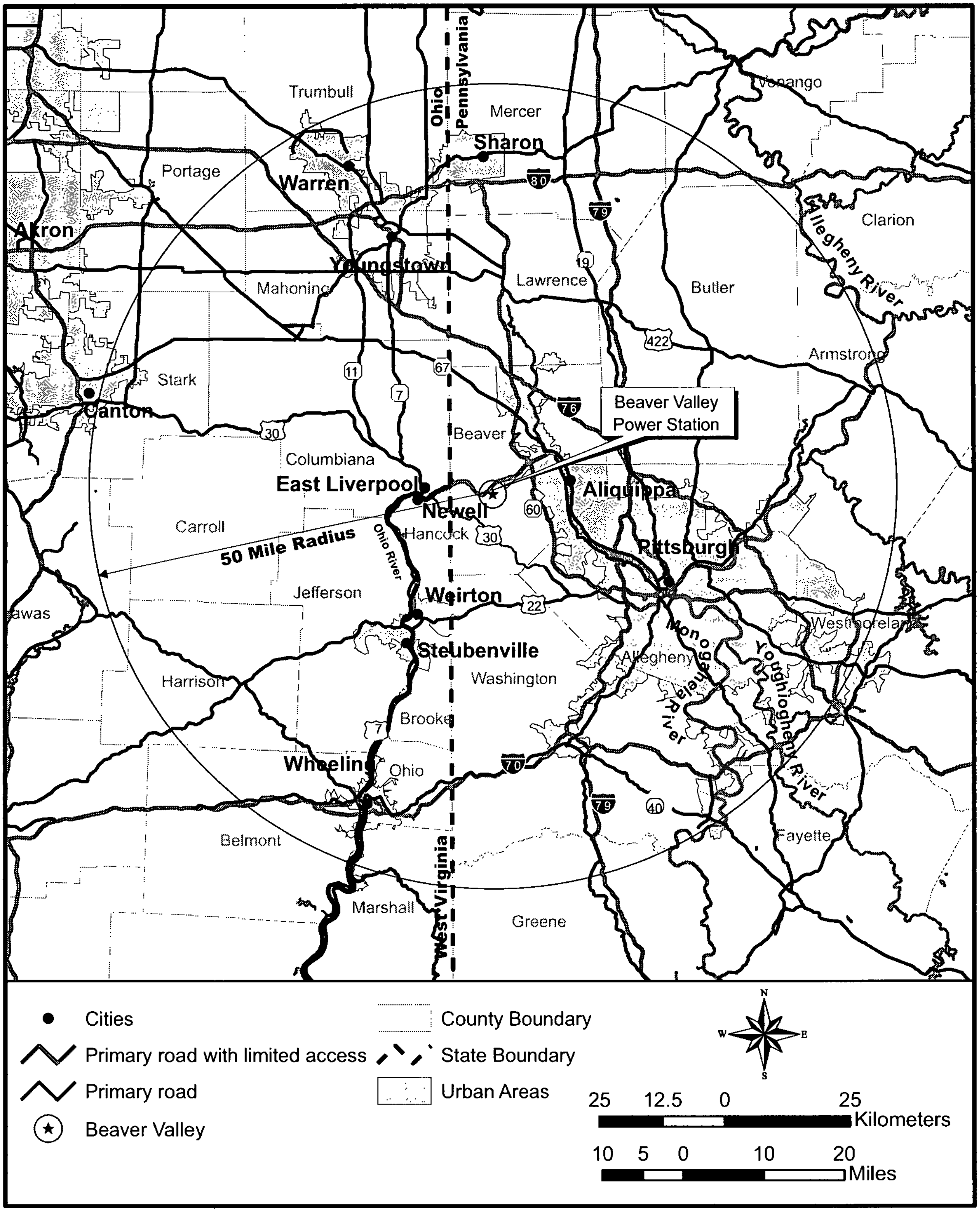


FIGURE 2.1-2

6-MILE VICINITY

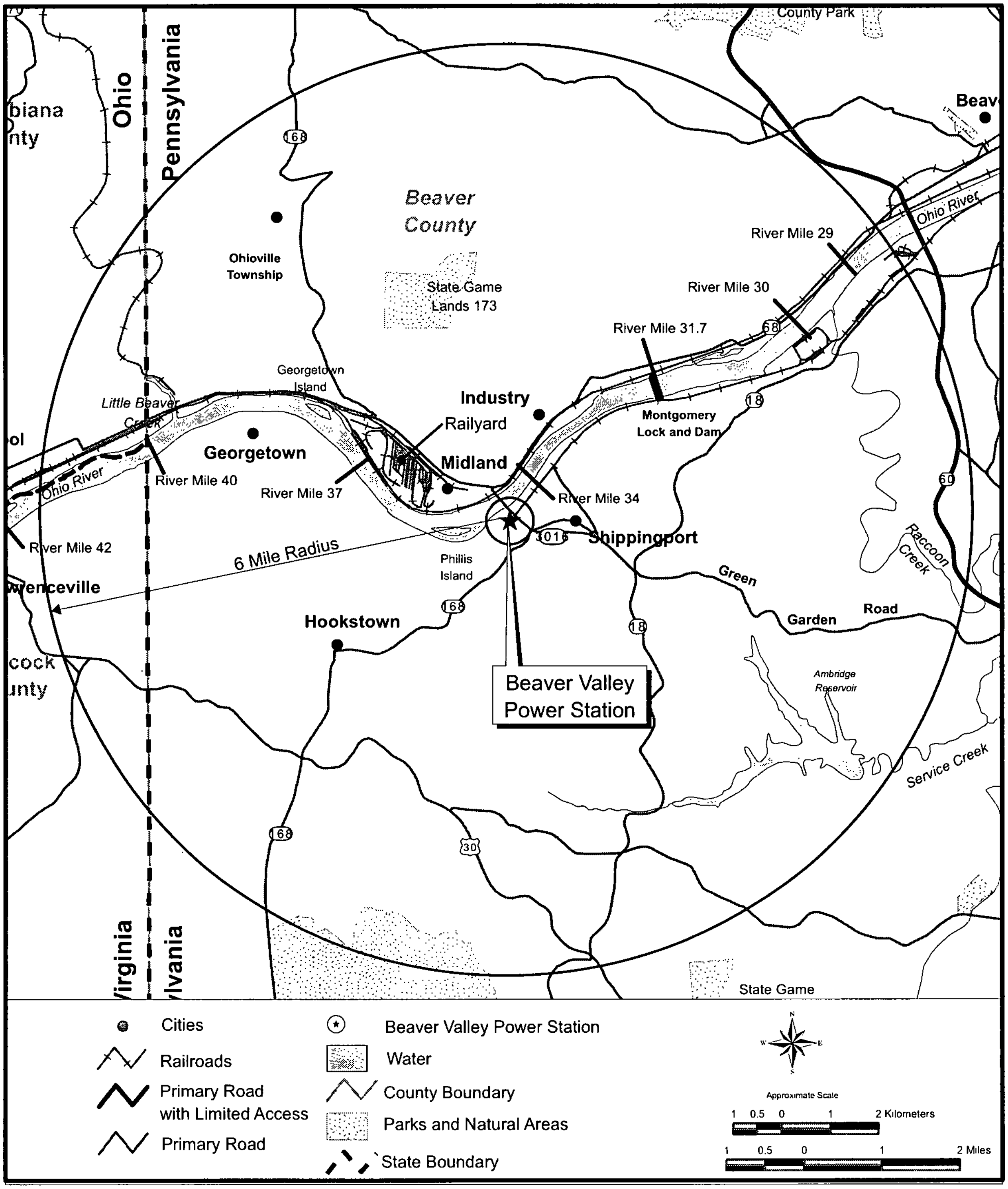
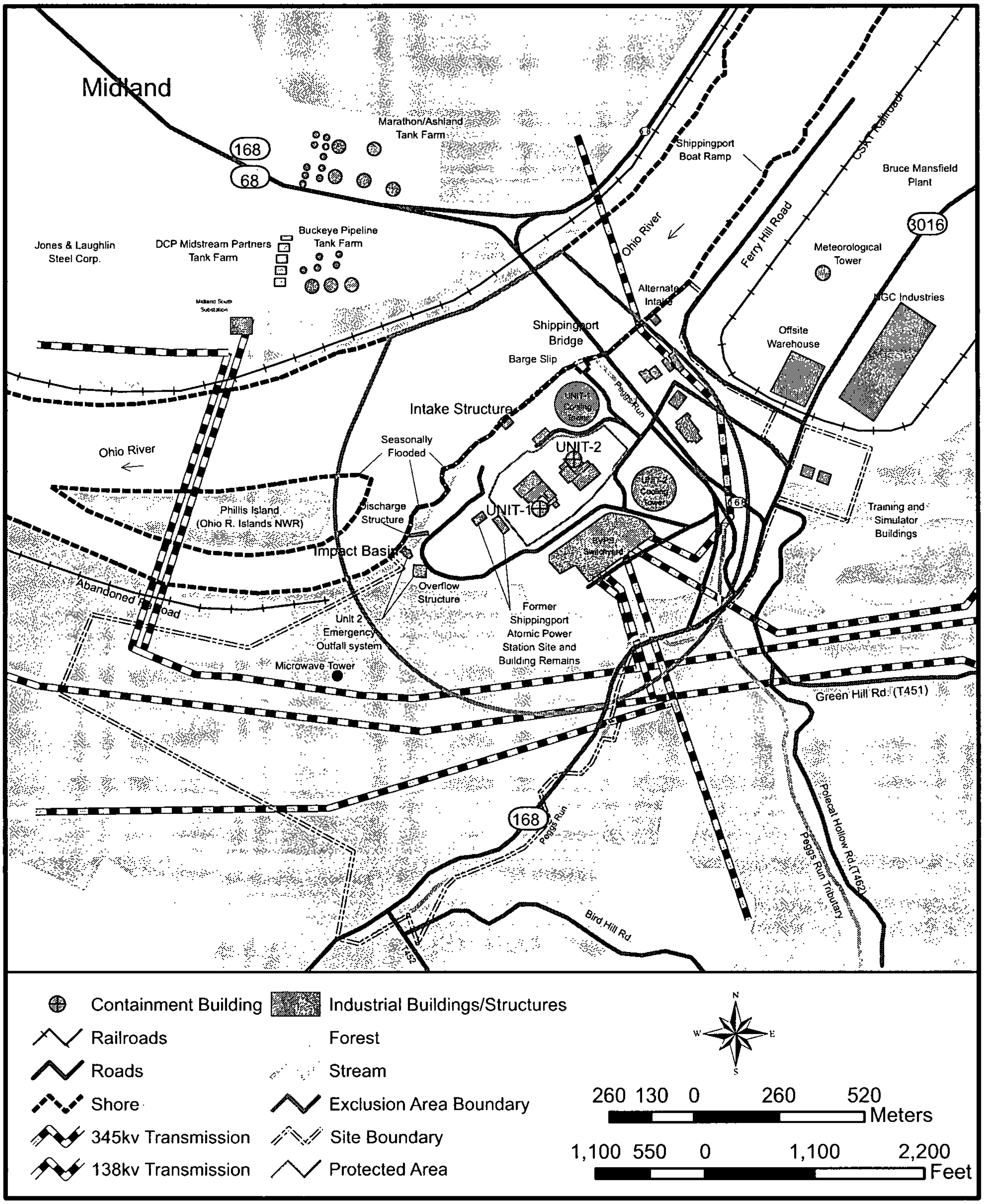


FIGURE 2.1-3

SITE MAP



2.1.2 Features in the Site Vicinity

BVPS is located on the New Cumberland Pool of the Ohio River, 3.1 river miles downstream from the Montgomery Locks and Dam (Figure 2.1-2) and 19.6 miles upstream from the New Cumberland Locks and Dam (Ref. 2.1-4, Section 2.4). More information about the Montgomery and New Cumberland Dams, and their associated reservoirs, will be provided in Section 2.2. The presence of the Ohio River and hilly topography of the area have contributed to the development of industrial river towns where the majority of industries and residences are concentrated on relatively level land adjacent to the river (Figure 2.1-2) (Ref. 2.1-4, Section 2.1). Further development in the BVPS site vicinity is hindered by existing development and topography (Ref. 2.1-5, Section 2.1-3). Rocky bluffs with steep forested hillsides separate industrial areas and towns within the river valley. Topography beyond the river valley is characterized by steep slopes and broad, relatively flat hilltops. Much of these rural upland areas are forested, particularly on slopes; pastureland, cropland, and new residential development predominates on the hilltops and gentler slopes, based on reconnaissance of the area and land use descriptions from the literature (e.g., Ref. 2.1-5, Section 2.1.3; Ref. 2.1-6).

The river valley upstream from the BVPS site to Pittsburgh is highly developed. Industrial development is particularly evident in and around the municipalities of Monaca, Rochester, and Aliquippa; the city of Beaver is more residential in character. Industrial facilities upstream from BVPS in the general site vicinity include a Horsehead Corporation zinc recycling plant, in Monaca, which is among the largest manufacturing employers in Beaver County (approximately 635 workers) (Ref. 2.1-6; Ref. 2.1-7). Others include the BASF Chemical plant, Nova Chemical plant, and AES Beaver Valley Cogeneration Facility, located approximately 6 river miles upstream (Ref. 2.1-6). All of these facilities are located on the Montgomery Pool. FENOC's Bruce Mansfield Plant (Figure 2.1-3), a 2,505-megawatt (MW) power plant with three coal-fired units, is located approximately 1 river mile upstream from the BVPS site on the New Cumberland Pool. Coal and lime needed for operations are transported to the Bruce Mansfield Plant by barge. Air emission control waste from the plant is pumped through 7 miles of underground pipeline, which passes through the BVPS site to a 1,300-acre disposal impoundment (Little Blue Run) approximately 4 miles southwest of the BVPS site. Some air pollution control waste from this plant is also used to produce more than 600 million square feet of gypsum wallboard annually at the National Gypsum Company plant (NGC Industries) (Figure 2.1-3), which is situated between the BVPS site and the Bruce Mansfield Plant (Ref. 2.1-8).

Development downstream from the BVPS site is centered in and around Midland, East Liverpool, and Newell, all on the New Cumberland Pool (Figure 2.1-2). Approximately 1 mile north of the site, across the Ohio River in the Borough of Industry (Figure 2.1-2), the Buckeye Pipeline Company and Marathon Ashland Petroleum (Figure 2.1-3) each operate bulk storage tank facilities for gasoline and fuel oil (Ref. 2.1-9). DCP Midstream Partners operate a bulk storage facility for propane adjacent to the Buckeye Pipeline facility to the west. A Jones & Laughlin Steel Corporation steel mill (Figure 2.1-3) is located approximately 1 mile downstream from the BVPS site, in Midland. Much of the industry in East Liverpool and Newell is dedicated to ceramics and pottery. The Homer Laughlin China Company, located in Newell, is one of the largest industries downstream from the site, employing approximately 1,100 workers (Ref. 2.1-10). FENOC's W.H. Sammis Power Plant is located approximately 21 river miles downstream from BVPS, immediately upstream from the New Cumberland Locks and Dam. This large power plant features seven coal-fired units and five oil-fired peaking units with a combined capacity of 2,316 MW (Ref. 2.1-11).

The USACE currently allows sand and gravel dredging in much of the New Cumberland Pool and has evaluated the environmental effects of allowing future commercial dredging activities, other than for navigational purposes, on the Ohio River between river miles zero and 40 (Ref. 2.1-12). Area reconnaissance in 2002 noted an active sand and gravel operation along the Ohio River, approximately 3 miles downstream from the BVPS site, in Georgetown.

Several creeks and river tributaries feed into the Ohio River near and within the BVPS site vicinity. The Beaver River joins the Ohio River approximately 9.5 river miles upstream from the BVPS site in the Montgomery Pool. Other notable tributaries within the BVPS site vicinity include Raccoon Creek (Figure 2.1-2), which outfalls approximately 4 river miles upstream from the site, and Little Beaver Creek, which outfalls approximately 5 river miles downstream. Portions of Little Beaver Creek are designated components of the state of Ohio and National Wild and Scenic Rivers Programs (Ref. 2.1-13). Ambridge Reservoir (Figure 2.1-2), approximately 5 miles southeast of the BVPS site, is an impoundment of Service Creek, a Raccoon Creek tributary. The impoundment serves as a municipal water supply for the city of Ambridge (Ref. 2.1-6).

Several public lands within or near the BVPS site vicinity are dedicated to wildlife management and recreation. These public lands include a portion of the Ohio River Islands National Wildlife Refuge, Raccoon Creek State Park, Pennsylvania Game Lands Number 189, Beaver Creek State Forest, Brady Run County Park, and Pennsylvania Game Lands Number 173 (Figure 2.1-2). Shippingport Community Park, a 7.5-acre public recreation facility, is located along SR 3016 in Shippingport. The Shippingport Boat Ramp is located approximately 800 feet upstream from the BVPS site eastern boundary on the Ohio River (Ref. 2.1-14) (see Figure 2.1-3).

Established in 1990, the Ohio River Islands National Wildlife Refuge currently consists of all or part of 21 Ohio River islands and 3 mainland tracts, encompassing 3,221 acres within a nearly 400-river-mile acquisition area from Shippingport, Pennsylvania, to Maysville, Kentucky. U.S. Fish and Wildlife Service (FWS) planning officials estimate that the refuge could include up to 35 river islands as acquisitions develop. The two islands located furthest upstream in the refuge, Phillis Island and Georgetown Island, are located within the BVPS site vicinity (Figure 2.1-2). Phillis Island (approximately 39 acres) is situated approximately 400 feet offshore of the downstream portion of the BVPS site and lies partially within the BVPS exclusion area. The 16.2-acre Georgetown Island is located approximately 3 river miles downstream from the BVPS site. The FWS has no plans to incorporate any other islands within the New Cumberland Pool into the refuge. (Ref. 2.1-15, Chapter 1; Ref. 2.1-16)

2.1.3 Beaver Valley Power Station Site Features

The BVPS site is characterized by sloping topography with the exception of the northeast corner, on which plant facilities are located. The nuclear portion of the power station, including the containment structure, auxiliary building, fuel building, and main control area, are situated on the uppermost of three terraces along the Ohio River, at an average elevation of approximately 735 feet National Geodetic Vertical Datum (NGVD). The cooling water intake and discharge facilities for the plant are located on the intermediate terrace (approximate elevation 688 feet NGVD) between the upper terrace and the present floodplain of the Ohio River (Ref. 2.1-4, Section 2) (see Figure 2.1-3).

Normal water level at the BVPS site (i.e., normal elevation of the Cumberland Pool) is approximately 664.5 feet NGVD; the 100-year flood elevation is approximately 695 feet NGVD (Ref. 2.1-17, Section 4.3). Peggs Run, a small stream flowing through the eastern portion of the site, is channeled through a culvert through most of the BVPS site and enters the Ohio River just west of the Shippingport Bridge (Figure 2.1-3).

As shown on Figure 2.1-3, the BVPS site is generally situated between the Ohio River to the north and roadways (SRs 168 and 3016, Ferry Hill Road) on the south and east. Generating facilities and the plant switchyard (Beaver Valley Substation) are located west of the southern approach to the Shippingport Bridge, which bisects the site. Support facilities are located west of the bridge approach.

Approximately 230 acres of the 453 acres of land on the site are developed or maintained, about the same as that reported in the BVPS-2 FES (Ref. 2.1-17, Table 4.1). The remainder of the site consists of forested areas (see Figure 2.1-3 and Ref. 2.1-17, Figure 4.1). Developed or maintained areas of the site encompass the plant, switchyard, and related support facilities and infrastructure; the former site of the Shippingport Atomic Power Station (SAPS).

SAPS operations were terminated in 1982 and the facility was decommissioned and partially dismantled by the U.S. Department of Energy (DOE). The electrical systems were deactivated and all irradiated piping and reactor components, including the reactor pressure vessel and neutron shield tank assembly, were removed from the site and shipped to a burial facility. Landscaped areas and transmission corridors were cleared for security purposes and the remaining SAPS facilities (e.g., control room, turbine deck and building, and intake structure) have been released for unrestricted use.

FENOC or its subsidiary companies own all property within the site boundary except one residential tract located along SR 168, and two tracts owned partly or wholly by Duquesne Light Company (Duquesne Light): the Beaver Valley Substation (approximately 24 acres, 50-percent owned by Duquesne Light), and the microwave tower property (approximately 1 acre, 100-percent owned by Duquesne Light). Several rights-of-way and easements exist on the site (Ref. 2.1-5, Section 2.1). These include rights-of-way for several pipelines for transport of natural gas and petroleum products and the pipeline from the Bruce Mansfield Plant for transport of scrubber slurry waste to the Little Blue Run disposal site. The Pennsylvania Department of Transportation (PDOT) has a right-of-way for the southern approach to the Shippingport Bridge

(SR 168). A small (less than 1-acre) family cemetery is situated in the eastern portion of the site near Ferry Hill Road, for which an easement has been granted for visitation and maintenance.

Shippingport Borough has zoned the entire site Industrial (I), except the tract on which the Training and Simulator Buildings are located, which is zoned Business (B) (Ref. 2.1-18). Some land adjacent to the site, south of State Route 168, is zoned residential. However, this area is small; consists of steep, wooded slopes; and has limited potential for growth (Ref. 2.1-18; Ref. 2.1-5, Section 2.1.3).

A 2,000-foot radius around the BVPS-1 containment building, with an extension to the north shore of the Ohio River, defines the combined boundaries of the BVPS-1 and BVPS-2 exclusion areas, as defined at 10 CFR 100.3 (Ref. 2.1-4, Section 2.1.1; Ref. 2.1-19, Section 2.1.1). The nearest residence to the site is located approximately 0.1 miles immediately northeast of the exclusion area boundary (Ref 2.1-20, Table 3-1).

FENOC or its subsidiary companies own all land within the BVPS exclusion area except the Ohio River proper, onsite property owned by Duquesne Light (i.e., switchyard tract, which is jointly owned by Duquesne Light and FENOC), and the eastern portion of Phillis Island, owned by the United States government and administered by the FWS. However, appropriate controls are in place to restrict use of these lands. In case of an emergency that threatens persons or the environment, FENOC has the authority to enter the switchyard, after notifying Duquesne Light, to take action to prevent damage, injury, or loss. Limited hunting is permitted on Phillis Island (Ref. 2.1-16), but no public assembly is allowed there (Ref. 2.1-4, Section 2.1).

Effective June 12, 2002, the U.S. Coast Guard (USCG) established a security zone encompassing all waters extending 200 feet from the shoreline of the southeastern shore of the Ohio River, from river mile markers 34.6 to 35.1. This rule, which was established for an indefinite period, prohibits persons or vessels from entering the security zone unless authorized by the USCG Captain of the Port of Pittsburgh or his designated representative (Ref. 2.1-21).

2.2 HYDROLOGY

In this section, FENOC describes the hydrologic characteristics and water use of the Upper Ohio River and its associated alluvial aquifers. Section 2.2.1 addresses surface water hydrology and use. Alluvial aquifer characteristics and use are described in Section 2.2.2.

2.2.1 Ohio River Surface Water Hydrology and Use

2.2.1.1 General Description

As indicated in Section 2.1, BVPS is located on the New Cumberland Pool of the Ohio River at approximate river mile 34.8, 3.1 river miles downstream of the Montgomery Locks and Dam (river mile 31.7) and 19.6 river miles upstream from the New Cumberland Locks and Dam (river mile 54.4) (Ref. 2.1-17, Section 4.3.1.1; Ref. 2.2-1). The New Cumberland Locks and Dam maintain a normal pool elevation of 664.5 feet NGVD at river flows up to about 20,000 cubic feet per second (cfs) (Ref. 2.1-12, Table 3-2; Ref. 2.1-17, Section 4.3.1.1). River flow at the BVPS site is highly regulated by the Montgomery Locks and Dam, Dashields (river mile 13.3) and Elmsworth (river mile 6.2) mainstem locks and dams, and numerous navigation locks and dams and reservoirs on the major tributaries upstream from the site, the Allegheny, Monongahela, and Beaver Rivers (Ref. 2.1-17, Section 4.3.1.1). The nearest U.S. Geological Survey (USGS) gauge upstream from the BVPS site is at Sewickley (0308600, river mile 13.3), which has a drainage area of 19,500 square miles (Ref. 2.2-3).

The only major tributary to the Ohio River mainstem upstream from the BVPS site, the Beaver River, joins the Ohio River at river mile 25.2 in the Montgomery Pool (see Figure 2.1-2). At the Beaver Falls USGS gauging station 03107500, 5.5 miles upstream from its confluence with the Ohio River, the Beaver River has a drainage area of 3,106 square miles with an average discharge of 3,760 cfs (Ref. 2.2-3).

2.2.1.2 Ohio River Low-Flows and Pool Level Reduction

The NRC described the low-flow characteristics of the Ohio River at the BVPS site in the mid-1980s in the BVPS-2 operating phase FES (Ref. 2.1-17, Section 4.3.1.1). That description reflected an update of low-flow estimates provided in the 1973 construction-phase licensing documentation to account for additional reservoirs with low-flow augmentation capabilities that had been constructed in the basin in the intervening period. The updated estimates, provided by the USACE, indicated that the once-in-10-year, 7-day-duration low flow (7Q10) at the site was approximately 5,200 cfs and that the minimum expected flow under conditions corresponding to the lowest flow of record, which occurred in 1930, would be approximately 4,000 cfs.

One major additional reservoir, Stonewall Jackson on the West Fork, was established in early 1990 (Ref. 2.2-5). To account for this additional reservoir and USGS flow data obtained since that time, FENOC performed a flow analysis similar to that reported in the BVPS-2 FES, using USGS flow data for the 1971 – 2000 period of record. The analysis used flow data from the USGS Sewickley gauge on the Ohio River and the Beaver Falls gauge on the Beaver River and included a calculation of monthly average flow statistics, a frequency distribution by month of daily flows, and low-flow statistics for various return intervals using a log-Pearson procedure, a technique also used by the USGS (Ref. 2.2-4).

For this 30-year period of record, the analysis indicates that the minimum monthly average flow at the BVPS site ranged from 5,549 cfs in October to 37,987 cfs in March (see Table 2.2-1). Monthly low flows at the 10-percentile level (average frequency of once in 10 years) were lowest in September (6,257 cfs), and annual low flow at the 10-percentile level was 8,850 cfs. A 7Q10 flow of 5,290 cfs was determined from the 1971 – 2000 USGS data set. Flows at or below the 5,290-cfs 7Q10 flow rate occur at the 1-percentile level during the months of July through November (see Table 2.2-1). The updated 7Q10 estimate of 5,290 cfs does not differ discernibly from the estimate of 5,200 cfs reported in the BVPS-2 FES, but is dissimilar to the USACE 7Q10 value of 5,750 cfs for the river at Montgomery Locks and Dam for the 1949 – 1979 period of record (Ref. 2.2-6).

The USACE maintains minimum pool levels in the upper Ohio River to ensure a minimum depth of 9 feet in the navigation channel (Ref. 2.1-12). Normal pool elevation for the New Cumberland Pool is 664.5 feet NGVD (Ref. 2.1-12, Table 3-2). The USACE indicated in 1973 that navigation pools would not be intentionally lowered under postulated flows as low as 800 cfs, such as could occur upon loss of a lock gate, noting also that bulkheads could be installed in 4 hours, during which time the pool would drop by only 1.8 feet (Ref 2.1-4, Section 2.4.11.1). Information from the USACE indicates that there has been no significant change in this control strategy (Ref. 2.1-6).

2.2.1.3 Consumptive Use

Water that is withdrawn from the river and not returned, termed consumptive use, reduces downstream flows. In some cases, consumptive use can result in conflict with other users or reduce available habitat for aquatic biota. Facilities equipped with closed-cycle cooling systems typically are characterized as consumptive water users due to evaporative losses. BVPS uses closed-cycle, natural draft cooling towers as their primary source of cooling.

Water withdrawn from the river upstream of the BVPS site and on the New Cumberland Pool for municipal supplies and industrial use generally is returned to the river directly (e.g., in the case of facilities equipped with once-through cooling systems) or after treatment (e.g., as treated sanitary wastewater), resulting in little appreciable consumptive use. Nonconsumptive water users on the New Cumberland Pool include two municipalities that withdraw water from the pool. The Borough of Midland has a water supply system with a rated capacity of 5 million gallons per day (mgd) or 7.7 cfs, and the city of East Liverpool has a water supply system with a rated capacity of 4.2 mgd (6.5 cfs (Ref. 2.2-8; Ref. 2.2-9). The connections served by the primary public water supplies in Beaver County are summarized in Table 2.2-2. In addition, the W.H. Sammis Power Plant has a total design intake flow of 1,803 mgd (2,790 cfs) (Ref. 2.2-10, page C2-10).

TABLE 2.2-1

SUMMARY OF OHIO RIVER FLOW CHARACTERISTICS AT BVPS[a]

Monthly Average Flow (cfs)													
	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Annual
Min	11,618	24,113	37,987	30,478	18,638	7,387	7,327	5,730	6,025	5,549	7,194	10,548	27,239
Max	91,624	98,337	116,315	104,796	101,267	81,578	55,868	48,947	42,106	56,360	95,006	96,835	59,884
Mean	50,064	57,196	69,944	59,745	42,635	30,738	21,805	16,526	17,610	21,561	35,536	51,771	39,503
Daily Flow Frequency by Percentile (cfs)													
	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Annual
1%	9,630	9,768	14,800	15,050	9,900	5,574	4,993	4,654	4,735	5,020	4,640	6,500	5,348
10%	16,230	18,580	33,140	24,360	14,850	8,710	7,370	6,408	6,257	7,490	10,910	19,380	8,850
50%	42,290	46,760	64,910	54,200	35,460	22,960	14,520	11,600	11,530	14,970	30,620	46,830	30,330

7-Day Low Flows by Recurrence Interval (cfs)			
2-yr	5-yr	10-yr	25-yr
7,070	5,850	5,290	4,750

a. Based on U.S. Geological Survey flow data from gauging stations at Sewickley (0308600, river mile 11.8) on the Ohio River and at Beaver Falls (03107500) on the Beaver River for the period of record 1971 – 2000 (Ref.2.2-4).

cfs = cubic feet per second
yr = year

River water consumption does result from withdrawals used to replace water lost, but primarily from evaporation, in closed-cycle cooling systems. Currently, two large industrial facilities on the New Cumberland Pool use closed-cycle cooling. Maximum consumptive loss from BVPS operation is approximately 26 mgd (40 cfs) (see Section 3.1.3.3), and consumptive loss from Bruce Mansfield Plant operation is approximately 37 mgd (57 cfs) (Ref. 2.2-11).

Development of new power plants or other facilities that use closed-cycle cooling systems in the upper Ohio River Basin could result in some future decrease in Ohio River flows at the BVPS site. The Pennsylvania Department of Environmental Protection (PADEP) estimates that in their Southwest District, which consists of 10 Pennsylvania counties in the Ohio River Basin, approximately 18 new power plants have been built or were scheduled to go on-line in the 15- to 20-year period since the original BVPS-1 and BVPS-2 operating licenses were issued (Ref. 2.2-12. Ref. 2.2-26). PADEP's estimate of combined water loss from the Ohio River Basin for these new facilities, most of which use cooling towers, is approximately 150 cfs (Ref. 2.2-12). A consumptive use of this magnitude is 2.8 percent of the 7Q10 flow and 0.4 percent of the annual average flow at the BVPS site.

Water withdrawals from the upper Ohio River are normally not restricted at present (Ref. 2.2-13). In Pennsylvania (also identified as the Commonwealth), riparian owners have the right to use adjoining surface waters in accordance with riparian doctrine, based on common law (Ref. 2.2-14). No water withdrawal permits are issued by the Commonwealth for industrial facilities like BVPS; however, the Commonwealth has recently instituted a requirement that users who withdraw or use more than 10,000 gallons per day (gpd) of surface water or groundwater, including BVPS, register and periodically report water use for purposes of water use planning (Ref. 2.2-16). Facilities located in Ohio that withdraw more than 100,000 gpd from the Ohio River must register their facilities and report actual withdrawals and return flows annually (Ref. 2.2-17). No comparable permitting or registration program is required for West Virginia industrial facilities that withdraw water from the river.

2.2.1.4 Future Changes in Navigation and Reservoir Systems

The USACE has undertaken an investigation, the Ohio River Main Stem Systems Study, to determine investments needed to provide an efficient navigation system on the river mainstem through 2070 (Ref. 2.2-18; Ref. 2.2-19). As part of this study, the USACE Pittsburgh District is placing emphasis on the uppermost three of the six locks and dams in their jurisdiction—Emsworth, Dashields, and Montgomery—because they are much smaller and of an earlier vintage than the New Cumberland, Pike Island, and Hannibal facilities. There are several strategies being considered for upgrade or replacement of the three smaller facilities, but USACE does not foresee major modifications to the New Cumberland Locks and Dam or changes in the New Cumberland Pool normal pool elevation (Ref. 2.2-18; Ref. 2.2-19).

There are no reservoirs in the proposed or planning stages in the Ohio River Basin (Ref. 2.2-20). However, the USACE has indicated to FENOC that there is interest by non-federal partners in conducting reallocation studies at Kinzua and Woodcock Dams in the Allegheny River watershed, an activity that holds some potential for lower releases during the summer months

(Ref. 2.2-21). If implemented, some reduction in river flows could result. However, in view of USACE's control strategy, as discussed above, pool levels would remain unaffected.

2.2.2 Ohio River Alluvial Aquifers and Use

2.2.2.1 General Description

Alluvial gravel and sand deposits of varying thicknesses occur over the underlying bedrock of the upper Ohio River valley near the BVPS site, frequently forming terraces. These terraces, deposited as glacial outwash during the Pleistocene Age, provide the substrata on which the majority of regional cultural and industrial centers, including BVPS, are built. They also hold large volumes of groundwater. Well yields in these alluvial aquifers commonly range from 500 to 1,000 gpm (Ref. 2.1-4, Sections 2.4.13, 2.5.1.1; Ref. 2.2-22, Section 2.6.2).

The expected general characteristics of alluvial aquifers that occur in the New Cumberland Pool, including those at Industry, Midland, Georgetown, and other downriver locations, are illustrated by the terrace and associated aquifer that underlie the BVPS site. This deposit is over 100 feet thick (Ref. 2.1-17, Section 4.3.1.2). Local recharge to the associated terrace aquifer is primarily from precipitation in its catchment, which flows downgradient through soils above the bedrock. Infiltration amounts to an average recharge of about 12 inches of water per year, or about 900 gpd per acre. Under normal river conditions, the groundwater levels under the terrace slope very gently to the northwest, toward the Ohio River (Ref. 2.1-4, Section 2.4). However, additional recharge to the aquifer also occurs from the Ohio River because it and the aquifer are hydraulically connected (Ref. 2.1-17, Section 4.3.1.2). Hydraulic conductivity of the alluvial deposits has been estimated to range from 1.7×10^{-3} to 6.1×10^{-3} centimeters per second (Ref. 2.1-17, Section 4.3.1.2).

2.2.2.2 Alluvial Aquifer Groundwater Use

The alluvial aquifers (Mississippian and Pennsylvanian) along the upper Ohio River are used as groundwater supply for numerous industries and municipalities. The Beaver County Planning Commission indicates that eight well fields for public water supply are established along the river in Beaver County (Ref. 2.1-6). Notable suppliers of potable water that draw from alluvial aquifers on the New Cumberland Pool and associated system-rated capacities include the Borough of Industry, at least 0.1 mgd (> 0.2 cfs); the Newell Company, which serves the municipality of Newell and portions of Grant Township, West Virginia, 1.8 mgd (2.8 cfs); and the municipality of Chester, West Virginia, 0.35 mgd (0.5 cfs) (Ref. 2.2-23; Ref. 2.2-24; Ref. 2.2-25). The connections served by the primary public water supplies in Beaver County are summarized in Table 2.2-2.

BVPS does not use groundwater wells, as domestic water is provided by the Midland Water Authority. Prior to 1996, BVPS had two onsite drinking water wells. The wells are no longer used. The pumps have been removed and the wells have been capped. SAPS, during its operation, also had a drinking water well from approximately 1956 through 1984. This well has been capped and disconnected from any pumps. FENOC has no plans to reactivate any of these wells for domestic or process water use.

During development of the BVPS Groundwater Protection Plan, FENOC evaluated the aforementioned wells and construction-era piezometers for use in monitoring. One former drinking water well and several piezometers were determined to be suitable for groundwater monitoring in addition to the installation of four new monitoring wells. Therefore, the only planned use of groundwater at BVPS is to perform monitoring in support of the groundwater protection program.

TABLE 2.2-2

Beaver County Primary Public Water Supply Systems

Water System	Source Type	Connections Served
Surface Water		
Ambridge Water Authority	Ambridge Reservoir	7,286
Beaver Falls Municipal Authority	Beaver River	17,026
Midland Borough Municipal Authority	Ohio River	1,051
Ground Water		
Aliquippa Municipal Water Authority	9 wells	6,874
Ankrom Acres Mobile Home Park	2 wells	28
Beaver Borough Municipal Authority	4 wells	1,787
Black's Mobile Home Park	2 wells	38
Center Township Water Authority	4 wells	4,686
Cole Mobile Home Park	3 wells	40
Colonial Glenn Estates	3 wells	35
Creswell Heights Joint Water Authority	5 wells	5,595
Forest Brook Mobile Home Park	9 wells	131
Glasgow Municipal Water Works	2 springs	20
Harshbarger Mobile Home Park	2 wells	48
Independence Park	5 wells	73
Industry Borough Municipal Authority	3 wells	689
Knob View Estates	12 wells	97
Little Creek Estates Mobile Home Park	2 wells	35
Midway Terrace Inc.	3 wells	15
Monaca Municipal Water Works	6 wells	2,889
Morgan's Mobile Home Park	4 wells	25
Outlook Points – South Beaver	4 wells	1
Pinehurst Mobile Estates	3 wells	25
Penn Hills Estate of Rodchester	2 wells	81
Sky View Terrace	3 wells	37
Sunrise Mobile Court	6 wells	28
Vanport Township Municipal Authority	7 wells	314

Source: Ref. 2.1-6a.

2.3 BIOLOGICAL RESOURCES

2.3.1 Aquatic and Riparian Ecological Communities

Waterbodies on and near the BVPS site include the upper Ohio River, in particular the New Cumberland Pool, and Peggs Run, a small tributary of the Ohio River that traverses the southeastern portion of the site (see Figures 2.1-2 and 2.1-3). The aquatic and riparian ecological communities of primary concern to this ER are those associated with the New Cumberland Pool, which FENOC describes in Sections 2.3.1.1 through 2.3.1.4. Peggs Run is described in Section 2.3.1.5.

2.3.1.1 New Cumberland Pool Physical Characteristics and Water Quality

The New Cumberland Pool is 23 miles long and averages approximately 1,325 feet wide, providing a surface area at normal pool elevation of 3,646 acres (Ref. 2.1-12, Table 3-2). Several islands, consisting of alluvial sand and gravel capped with sediments deposited by flooding, remained in the river following its impoundment. Four of these islands currently exist: Phillis Island (river mile 35), offshore from the downstream end of the BVPS site; Georgetown Island (river mile 38), near Georgetown; Babbs Island (river mile 42), at East Liverpool, Ohio; and Cluster Island (river mile 52), approximately 2 miles upstream from the New Cumberland Locks and Dam. Three former islands, Baker Island (river mile 49.5) and two other islands associated with Cluster Island, have been eroded and are now submerged at the normal pool elevation of 664.5 feet NGVD (Ref. 2.1-12, Table 3-2; Ref. 2.3-1; Ref. 2.2-1; Ref. 2.3-2, Chapter 1, page 2, and Chapter 3, page 16).

The Federal Energy Regulatory Commission (FERC) indicates that seven embayments (mouths of tributary streams flooded as a result of river impoundment) over 500 feet long occur in the New Cumberland Pool; the total combined length of these embayments is 4.4 miles (Ref. 2.3-3, Section 3.5.5.8). The most notable of these are narrow, steep-sided stream channels at the mouths of Little Beaver Creek (river mile 39), near Georgetown and Yellow Creek (river mile 50), approximately 1 mile downstream from Wellsville, and the relatively broad Tomlinson Run Embayment (river mile 53), approximately 1 mile upstream from the New Cumberland Locks and Dam. Aquatic backwaters associated with the pool, represented by these embayments, reportedly total approximately 180 acres (Ref. 2.3-3, Section 3.5.3.5).

The New Cumberland Pool consists predominantly of deep channel habitat with low current velocities. A navigation channel of a minimum 9-foot depth at normal pool elevation is maintained (Ref. 2.2-2); however, average depth is much deeper, approximately 20 feet in its upper reach. The channel is relatively steep-sided, with depths less than 9 feet generally occurring only within approximately 100 feet of the shoreline, over the submerged islands, and around the perimeters of existing islands. Notable exceptions are the flooded mouths of tributaries and the head and foot of the river islands where areas less than 5 feet deep at normal pool elevation may extend for several hundred feet (Ref. 2.1-12, Sections 3.1.1 and 3.1.2.3, Figure D-1; Ref. 2.2-1; Ref. 2.1-4, Figures 2.4-8 through 2.4-11).

Bottom substrate of the upper Ohio River is predominantly a mixture of sand and gravel deposited from glacial meltwaters via the Allegheny River and finer materials, including fine sand, silt, and clay, from the Monongahela River. Because of the high quality and quantity of these sand and gravel deposits, commercial dredging has occurred in numerous areas of the upper New Cumberland Pool. Much of the upper pool—except for established buffer zones to protect nearshore areas, islands, island backchannels, and the navigation channel—consists of sand and gravel deposits identified as potentially suitable for future dredging (Ref. 2.1-12, Sections 3.2.3, 3.2.4, Figure A-1).

The distribution of substrate types in the pool is a function of current velocities and patterns. Typically, tailwater habitat, such as exists below the Montgomery Locks and Dam, consists of a deep scour zone where boulders and cobbles extend approximately 200 feet downstream followed by relatively shallow gravel deposits where current remains relatively high (Ref. 2.3-3, Section 4.1.2.2). FWS studies of islands in the pool (Ref. 2.3-4) indicate that sand, gravel, and cobbles predominate at the heads of islands where currents are relatively high; these areas and the dam tailwaters were noted as most closely resembling natural run/riffle habitat that existed prior to impoundment of the river. The sides and toes of the islands are typically a combination of finer materials, including sand, silt, clay, and detritus as a result of slower current velocities and shoreline accretion (Ref. 2.3-4). Substrate composition near the BVPS site, based on observations during annual benthic macroinvertebrate sampling, generally consists of soft sediments, including sand, silt, and detritus, in nearshore areas except along the north shoreline of Phillis Island where clay and sand predominate. Coarser gravel and cobble substrates occur in the middle of the Phillis Island backchannel (Ref. 2.3-5, Section 5.4.1).

The upper Ohio River has undergone considerable improvements in water quality since the mid-twentieth century. In the late 1960s, water quality in the New Cumberland Pool was dominated by acid mine drainage discharges; large numbers of waste discharges were also present. However, gradual improvements had been noted in the subsequent 20 years (Ref. 2.2-22, page 2-8). NRC's comparison of water quality data from 1976 – 1980 with that from 1968 – 1970 indicated that water quality continued to improve. In particular, alkalinity increased and sulfates, iron, and manganese decreased, indicating reduced acid mine drainage input. The NRC noted reduced concentrations of ammonia and nitrate nitrogen, indicating reductions in sewage treatment pollutants. However, the NRC also noted that annual mean concentrations for some years from 1976 – 1980 for phenolics, copper, total iron, lead, mercury, and zinc exceeded water quality criteria (Ref. 2.1-18, Section 4.3.2).

Currently, the Ohio River Valley Water Sanitation Commission (ORSANCO) issues biennial assessments of water quality on the Ohio River on the basis of frequent monitoring of numerous conventional pollutants and chemical constituents, including those mentioned above, dissolved oxygen, bacteria (e.g., fecal coliforms), and many others and on monitoring of biological parameters, including fish population characteristics, and analysis of fish tissue contaminants. Water quality of various river segments is rated for designated uses with respect to established ORSANCO water quality criteria as "fully supporting," "partially supporting," and "not supporting" (Ref. 2.3-6). In its 2006 assessment report, ORSANCO rated the New Cumberland Pool as "fully supporting" in the "Aquatic Life Use" assessment and the "Public Water Supply Use" assessment categories, but only "partially supporting" in the "Fish Consumption Use" assessment category as a result of fish consumption advisories that were in effect for mercury, polychlorinated biphenyls (PCBs), and dioxin (Ref. 2.3-6, Table 3, 4, and 7). ORSANCO rated the New Cumberland Pool in the "Contact Recreation Use" assessment category as "not supporting" because of coliform criteria exceedences (Ref. 2.3-6, Table 6).

The NRC (Ref. 2.1-17, Section 4.3.2) reported that monthly average Ohio River water temperatures for the period of record 1964 – 1977 ranged from 36.5 degrees Fahrenheit (°F) in January to 79.5°F in August, and that the maximum expected ambient river temperature was approximately 86°F. Daily average river temperatures recorded by the USACE Pittsburgh District at Montgomery Locks and Dam for a more recent period of record (1988 – 2002) show similar results. The highest maximum monthly average temperatures for this recent period occurred in July (80°F) and August (79°F); the maximum daily average temperature observed was 86°F, noted in both July and August (Ref. 2.3-8).

2.3.1.2 New Cumberland Pool Riparian Communities

An examination of USGS topographic maps (Ref. 2.3-1), FWS National Wetland Inventory maps (Ref. 2.3-9), and aerial photographs (Ref. 2.3-10) indicates that near-natural vegetation communities in the riparian zone of the pool consist mostly of narrow strips of forested land on relatively steep slopes between active or abandoned rail lines and the river. Vegetation communities on gentler slopes and bottomlands along the shoreline of the pool have been largely eliminated or are highly disturbed as a result of intensive development in the river valley (see Section 2.1).

Other than open water, wetlands in or adjacent to the New Cumberland Pool are generally small, few, and scattered. Riparian zone communities, including wetlands, in or bordering the pool, that relatively high natural resource value, include Phillis Island (39 acres) and Georgetown Island (16 acres). These islands are the uppermost islands in the Ohio River Islands National Wildlife Refuge, established in 1990 (Ref. 2.1-15).

Four wetland areas are considered by the FWS to be priority fish and wildlife wetland and embayment areas (Ref. 2.3-11, page 2-15, Appendix E; Ref. 2.3-2; Chapter 1):

- Palustrine forest (4 acres) along the south shoreline at the BVPS site between the intake and discharge structures, which has developed on sand and gravel deposits intermixed with clay and silt. Based on a reconnaissance-level survey of terrestrial communities conducted by FENOC in July 2002 on the BVPS site and nearby riparian zone (Ref. 2.3-12), two terrestrial communities exist on and near this site: silver maple floodplain forest, which predominates, and a small area of willow scrub. The forest community is dominated by silver maples (*Acer saccharinum*) and black willows (*Salix nigra*), exhibiting a mostly closed tree canopy. Herbaceous cover in this area at the time of the survey was moderate, consisting predominantly of false nettle (*Boehmeria cylindrica*), American germander (*Teucrium canadense*), and white vervain (*Verbena urticifolia*). The willow scrub community consists of saplings and smaller trees, dominated by black willow, and includes sycamore (*Platanus occidentalis*), silver maple, and box elder. False nettle was predominant in the herbaceous layer of the willow scrub community at the time of the survey. Two low areas associated with these vegetated communities are generally connected with the river, forming small areas of shallow open-water habitat. The silver maple floodplain forest and willow scrub community correspond to areas classified as silver maple-sycamore forest at the time of BVPS-2 initial operation (Ref. 2.1-17, Figure 4.1). Some selective cutting of larger trees from portions of the original community along the river was conducted in late 2001 to enhance security at the BVPS site.

- Palustrine forest (14.4 acres) and immature bottomland forest (7.5 acres) in the riparian zone on the north shore of the river off the head of Georgetown Island.
- Palustrine forest (7.5 acres), palustrine open water (2.5 acres), and immature bottomland forest (21.3 acres) at and near the mouth of Congo Run, at river mile 47.5, approximately two miles downstream from Newell, WV.
- Palustrine emergent (3.8 acres), riverine open water (41 acres), and immature bottomlands (18.7 acres) associated with the Tomlinson Run Embayment.

Based on mapping studies cited by the USACE (Ref. 2.1-12, Section 3.4.1.3), riverine aquatic bed habitat; i.e., areas dominated by submerged rooted aquatic plants, is generally sparse in the upper Ohio River and is typically associated with shore zone, tributary confluence, and island margin areas. Virtually no aquatic beds were found in the New Cumberland Pool during these mapping studies.

Table 2.3-1 summarizes the description of major habitats encountered in the islands survey (Ref. 2.3-4), which provides a representative indication of typical vegetation composition and associated fish and wildlife value of bottomland, wetland, and submerged aquatic bed communities of the New Cumberland Pool.

Aside from the palustrine communities on and near the FWS priority area fronting the BVPS site, the riparian zone at the site is largely developed land. However, a plant community corresponding to the bottomland hardwood types that occur on New Cumberland Pool islands, as described in Table 2.3-1, also occurs in the riparian zone of the south shore of the river, particularly between the Phillis Island backchannel and the BVPS site boundary. FENOC mapped and described this area as black locust-hardwood forest during the July 2002 terrestrial reconnaissance survey (Ref. 2.3-12).

2.3.1.3 New Cumberland Pool Benthic Macroinvertebrate and Freshwater Mussel Communities

Based on data compiled by the USACE (Ref. 2.1-12, Section 3.4.2.2, Table 3-7), the benthic macroinvertebrate community in the New Cumberland Pool consists predominantly of oligochaetes. Taxonomic richness (a total of 134 taxa) and diversity (Shannon-Wiener diversity index value of 2.9) reported for that compilation were relatively high compared to lower pools of the Allegheny River and Dashields Pool on the Ohio River at Pittsburgh. Benthic macroinvertebrates have been sampled by Duquesne Light and FENOC since the mid-1970s

(Ref. 2.3-5). Sampling results for 2004 and 2005 are typical of findings in recent years (Ref. 2.3-5; Ref. 2.3-13). A total of 57, 37, and 40 taxa were collected in 2004, 2005, and 2006, respectively. Oligochaetes and midge larvae were found in highest densities and were reflective of the soft substrates that predominate in nearshore areas most subjected to sampling. Asiatic clams (*Corbicula fluminea*) and zebra mussels (*Dreissena polymorpha*) were collected in both years. Asiatic clams have been observed in the Ohio River since 1974; zebra mussels were first detected at the BVPS site in 1995. Both of these bivalves are introduced species that can cause fouling of water intakes and cooling water systems (Ref. 2.3-5, Section 5.4.1). Zebra mussels are also a recognized threat to native freshwater mussels (Ref. 2.3-14).

Native freshwater mussels of the family *Unionidae* are currently a minor component of the benthic invertebrate community in the upper Ohio River, but are of generally recognized importance from a conservation standpoint. This group, once abundant in the free-flowing Ohio River, was reduced in species diversity and abundance by impoundment of the river and by pollutants, but has shown evidence of resurgence in recent years (Ref. 2.3-3, Section 3.1.4.1; Ref. 2.3-14). This resurgence is attributed to improved water quality in the river. However, riverine mussel habitat has been permanently altered from a rapidly flowing river to a more pool-like environment and, although a new mussel fauna may become established, its composition is not expected to be the same as it was prior to impoundment (Ref. 2.3-3, Section 3.1.4.1). Most of the riverine mussel species found in the upper Ohio River require clean-swept, coarse sand and gravel substrates (Ref. 2.1-12, Appendix J). As noted in Section 2.3.1.2, a semblance of shallow riverine habitat featuring such substrates is now represented primarily in dam tailwaters and higher current areas around the river islands.

Information from the FWS provides an indication of the current status of mussel fauna in the New Cumberland Pool (Ref. 2.3-14; Ref. 2.1-12, Appendix J). Based on these sources, the New Cumberland Pool is the upstream-most pool in the Ohio River where live unionids have been reported. Of at least 36 species noted as historically present in the pool, the following 9 species have been reported, primarily from surveys conducted in the upper Ohio River from 1993 to 1997: mucket (*Actinonaias ligamentina*), fatmucket (*Lampsilis siliquoidea*), fluted shell (*Lasmigona costata*), fragile papershell (*Leptodea fragilis*), pink heelsplitter (*Potamilus alatus*), giant floater (*Pyganodon grandis; formerly Anodonta grandis*), mapleleaf (*Quadrula quadrula),* fawnsfoot (*Truncilla donaciformis*), and paper pondshell (*Utterbackia imbecillis*). These species were found in low numbers, primarily in the Montgomery Dam tailwaters and in the backchannel of Phillis Island. All of these species except the mucket were found at the latter site. No unionids were found in either of these areas in 1983, suggesting that unionids have colonized or abundance has increased since that time (Ref. 2.3-14; Ref. 2.1-12, Appendix J). Information from the Pennsylvania Department of Conservation and Natural Resources (Ref. 2.1-12, Appendix J) indicates that several of the unionid species recently found in the pool, including fragile paper shell, pink heelsplitter, mapleleaf, and fawnsfoot, had not been previously reported there since the early 1900s.

TABLE 2.3-1

ECOLOGICAL COMMUNITIES OF THE UPPER OHIO RIVER ISLANDS[a]

Community	Typical Vegetation	Associated Fish and Wildlife Values
Mature Bottomland Hardwoods	Represents the oldest vegetation stands on the islands; approximately 9 acres of this habitat reportedly occurs on Phillis Island. Predominant overstory species include silver maple (*Acer saccharinum*), sycamore (*Platanus occidentalis*), cottonwood (*Populus deltoides*), slippery elm (*Ulmus rubra*), box elder (*Acer negundo*), and black willow (*Salix nigra*). Among major subdominants are hackberry (*Celtis occidentalis*), black locust (*Robinia pseudo-acacia*), and green ash (*Fraxinus pennsylvanica*). Predominant shrub-layer species include spicebush (*Lindera benzoin*), Virginia creeper (*Parthenocissus quinquifolia*), and poison ivy (*Rhus radicans*). Herbaceous groundcover species include pale and spotted touch-me-not (*Impatiens spp.*), wingstem (*Verbesina alternifolia*), white snakeroot (*Eupatorium rugosum*), clearweed (*Pilea pumila*), Japanese knotweed (*Polygonum cuspidatum*), and sachaline (*Polygonum sachalinense*). The latter two species, both exotics, sometimes form nearly impenetrable thickets.	This habitat provides food, cover, and nesting habitat for a variety of wildlife species, including • Cavity-nesting birds and mammals such as wood duck (*Aix sponsa*), owls, woodpeckers, fox squirrel (*Sciurus niger*), and raccoon (*Procyon lotor*); • Canopy dwellers such as numerous resident and migratory songbirds, osprey (*Pandion haliaetus*), and herons; and • Understory species such as white-tailed deer (*Oedocoileus virginiana*), short-tailed shrew (*Blarina brevicauda*), and wood thrush (*Hylocichla mustelina*).
Immature Bottomland Hardwood	Characteristic dominant and subdominant woody species similar to those of mature bottomland hardwoods. However, trees are younger and may consist of only one or a few species in areas that have been cleared of vegetation. This community type on Phillis Island was noted to comprise 5 acres and be relatively diverse, an observation confirmed by a FENOC reconnaissance-level survey of the island in July 2002 (Ref. 2.3-12).	This habitat provides food and cover for a variety of resident and migratory songbirds. Also, it provides browse and cover used by white-tailed deer, young trees used by beaver (*Castor canadensis*), and food and cover for waterfowl (e.g., wood duck).

TABLE 2.3-1 (CONTINUED)

ECOLOGICAL COMMUNITIES OF THE UPPER OHIO RIVER ISLANDS[a]

Community	Typical Vegetation	Associated Fish and Wildlife Values
Early Oldfield	Coverage 90 percent or more by herbaceous species, including a variety of grasses, forbs, creepers, climbers, parasites, and composites, often forming thickets. Dead vegetation often forms a thick mat in winter. Approximately 1 acre of this community type was noted on Phillis Island.	Relatively high-value food, cover, nesting, and resting habitat for many wildlife species, including a variety of songbirds. Mammals using such areas include meadow vole (*Microtus pennsylvanicus*), short-tailed shrew, white-tailed deer, woodchuck (*Marmota monax)*, cottontail rabbit (*Sylvilagus florinanus*), beaver, and muskrat (*Ondatra zibethicus*).
Late Oldfield	Diverse community of shrubs, young trees, and herbaceous species that occur in other island community types, except wetlands. Other characteristic woody species include black locust, blackberry (*Rubus spp.*), staghorn sumac (*Rhus typhino*), and black elderberry (*Sambucus canadensis*). This community type comprises 2 acres on Phillis Island.	High-value food, cover, nesting, and resting habitat for many wildlife species, including a variety of songbirds. Mammals using such areas include white-footed mouse (*Peromyscus leucopus*), white-tailed deer, woodchuck, and cottontail rabbit.
Knotweed	Composed almost entirely of two exotic species, Japanese knotweed, normally predominant, and sachaline (*Reynoutria sachalinensis*). Often forming thickets up to 10 feet high, growth of understory species is often precluded. Five acres of this habitat were noted as existing on Phillis Island. A reconnaissance-level survey of Phillis Island by FENOC in July 2002, confirmed existence of a knotweed thicket at the head of the Island (Ref. 2.3-12).	Low value to wildlife due to relative lack of insect colonization and source of edible seeds. Forms mats of dead vegetation in winter and likely serves as cover for some wildlife species (e.g., small mammals).

TABLE 2.3-1 (CONTINUED)

ECOLOGICAL COMMUNITIES OF THE UPPER OHIO RIVER ISLANDS[a]

Community	Typical Vegetation	Associated Fish and Wildlife Values
Unconsolidated Shoreline	Seasonally and intermittently flooded beaches, bars, and sides and toes of steep eroded banks. Substrates widely variable depending on local source material and exposure to waves, river currents, and wind and include silt, hard clay, sand, gravel, and cobbles. Vegetation is sparse, limited to pioneer species; e.g., horsetail (*Equisetum spp.*), curley dock (*Rumex crispus*), smartweed (*Polygonum spp.*), lambsquarters (*Chenopodium album*), and pigweed (*Amaranthus spp.*). Approximately 2 acres of this community were noted on Phillis Island.	Species closely associated with unconsolidated shores include muskrat, beaver, raccoon, wood duck, Canada goose, great blue heron (*Ardea herodias*), spotted sandpiper (*Actitis macularia*), killdeer (*Charadrius semipalmatus*), kingfisher (*Ceryle alcyon*), and swallows.
Palustrine Emergent	Characterized by erect, rooted, herbaceous hydrophytes, at least remnants of which are generally persistent throughout the year, including sensitive fern (*Onoclea sensibilis*), broad-leaved cattail (*Typha latifolia*), duck potato (*Sagittaria latifolia*), sedges (*Cyperus spp.*, *Carex spp.*), spike rushes (*Eleochris spp.*), rushes (*Scirpus spp.*), smartweeds, and others. Not noted on Phillis Island.	Provides feeding and resting habitat for migratory shore and wading birds such as herons, egrets, killdeer, and sandpipers; food and cover for raccoons and muskrats; and nesting habitat for mallards (*Anas platyrhynchos*) and red-winged blackbirds (*Agelaius phoeniceus*). Typical amphibians and reptiles include green frogs (*Rana clamitans*), bullfrogs (*Rana catesbiana*), softshell turtles (*Trionyx spiniferus*), snapping turtles (*Chelydra serpentina*), and water snakes (e.g., *Nerodia sipedon*).
Riverine Emergent	Similar in character to palustrine emergent wetlands, but are generally non-persistent because high water and ice often remove remnant previous seasonal growth during winter and early spring, after which habitat characteristics are consistent with unconsolidated shoreline. Typical species present during the growing season include duck potato, water plantain (*Alisma subcordatum*), marsh purslane (*Ludwigia palustris*), water willow (*Justicia americana*), and hedge hyssop (*Gratiola neglecta*). Not noted at Phillis Island.	Provides habitat values consistent with unconsolidated shoreline during non-growing season. From late spring through fall, dieback provides valuable nursery habitat for juvenile fish and food and cover for numerous species of shiners (*Notropis spp.*) and other small fish.

TABLE 2.3-1 (CONTINUED)

ECOLOGICAL COMMUNITIES OF THE UPPER OHIO RIVER ISLANDS[a]

Community	Typical Vegetation	Associated Fish and Wildlife Values
Riverine Aquatic Bed	Characterized by beds of submerged, rooted aquatic plants such as water milfoil (*Myriophyllum heterophyllum*) and pondweeds (*Polygonum spp.*). Not noted at Phillis Island.	Extremely important to fish and waterfowl. Provides nursery areas for juvenile game fish such as black bass (*Micropterus spp.*), freshwater drum (*Aplodinotus grunniens*), sunfish (*Lepomis spp.*), and channel catfish (*Ictalurus punctatus*) and food and cover for minnow and shiner species. This forage fish concentration attracts predator species. Provides feeding habitat for migratory waterfowl, including Canada goose, mallard, black duck (*Anas rubripes*), wood duck, northern pintail (*Anas acuta*), and blue-winged teal (*Anas discors*).

[a]Except as otherwise noted, based on descriptions of New Cumberland Pool islands by the U.S. Fish and Wildlife Service (Ref. 2.3-4).

Relatively few unionids have been found in the course of the BVPS benthic macroinvertebrate monitoring program, which employs relatively fixed control and non-control stations to better discern the impact of BVPS site operations and enable year-to-year data comparisons. Collections consist of several specimens of giant floater at several sampling stations, both control and non-control, in 1997 (Ref. 2.3-16, Table 2.3). Seven immature *Anadonta* specimens were collected in 1992, unidentified immature unionids were collected in a few years in the 1970s and early 1980s, and one or more specimens of *Elliptio* were collected in 1978 (Ref. 2.3-17). Only 13 percent of the pool area was reportedly sampled as of 1999, of which an estimated 24 percent yielded unionids (Ref. 2.3-14, Table 3-1).

2.3.1.4 New Cumberland Pool Fish Community

Ohio River fisheries have improved substantially since the mid-twentieth century, a fact that has been broadly observed and generally attributed to greatly improved water quality in the river. This phenomenon was noted by the NRC as a contributing factor to increases in the then-current number of fish species and increased proportion of sport fishes, as cited in monitoring studies supporting the BVPS-2 operating-phase FES in 1985 and compared to results from monitoring conducted in 1968 –1971 prior to BVPS-1 startup (Ref. 2.1-17). The Pennsylvania Fish and Boat Commission (PFBC) cites several studies indicating that, since the 1970s, many riverine species have expanded their range or abundance in the Pennsylvania portion of the river, including spotted bass (*Micropterus punctulatus*) and freshwater drum (*Aplodinotus grunniens*) and pollution-tolerant species including mooneye (*Hiodon tergisus*), goldeye (*Hiodon alosoides*), redhorse (*Moxostoma spp.*), walleye (*Stizostedion vitreum*), and sauger (*Stizostedion canadense*) (Ref. 2.3-18). These water-quality improvements prompted the PFBC to begin restoration efforts for extirpated paddlefish (*Polyodon spathula*) in the Ohio River (Ref. 2.3-18). These efforts have included stocking paddlefish fingerlings in the Commonwealth's portion of the Ohio River, including the New Cumberland Pool, in even-numbered years since 1994, at a target rate of two fish per acre (Ref. 2.3-19). The Fish & Boat Commission stocked the Ohio River with about 755,000 10-inch-long paddlefish between 1994 and 2003. In 2002, an on-going joint project involving Penn State, California University of PA and the Pennsylvania Fish & Boat Commission, tracked 32 paddlefish in over 700 locations within 2.5 months using surgically implanted transmitters (Ref. 2.3-19a)

As explained below, an indication of fish species composition and abundance in the New Cumberland Pool is provided by results of sampling efforts by the ORSANCO, PFBC, and the Ohio Department of Natural Resources (ODNR). Long-term monitoring related to BVPS startup and operation, conducted by FENOC and Duquesne Light, has also contributed substantially to the body of known information about fish populations in the pool.

ORSANCO collection data for a 10-year period (1992 – 2002) from lock-chamber sampling in both the New Cumberland and Montgomery Locks and sampling in the New Cumberland Pool (Ref. 2.3-20) indicate that the fish community is diverse and abundant, consistent with observations of continued improvement of the fish community of the Upper Ohio River as discussed above. ORSANCO's repeated sampling, conducted for 7 years in this 10-year period, yielded a total of 32,162 fish representing 53 identifiable species and 4 hybrids. Rough and forage species are indicated in relatively high abundance by both collection methods. Gizzard shad (*Dorosoma cepedianum*), which contributes substantially to the forage base, and freshwater drum, a rough species, were the most abundant species in both collections, together accounting for 46 and 81 percent of the catch, respectively. Other forage species, individually comprising approximately 5 percent or more of the catch by a particular method, include emerald shiner (*Notropis atherinoides*), mimic shiner (*Notropis volucellus*) and channel shiner (*Notropis wickliffi*), and silver chub (*Macrhybopsis storeriana*) (Ref. 2.3-20). However, ORSANCO reported the presence of both the mimic shiner (Notropis volucellus) and the channel shiner (N. wickliffi), once considered a subspecies of the mimic shiner. Based on range and habitat information by Trautman (Ref. 2.3-2), individuals reported as mimic shiners are likely to be channel shiners. Common carp (*Cyprinus carpio*), skipjack herring (*Alosa chrysochloris*), and two sucker species (smallmouth buffalo [*Ictiobus bubalus*] and golden redhorse [*Moxostoma erythrurum*]) are also indicated as present in relatively high abundance. Relatively abundant sport fishes include channel catfish (*Ictalurus punctatus*), white bass (*Morone chrysops*), and bluegill (*Lepomis macrochirus*), which were numerous in both pool and lock-chamber samples; flathead catfish (*Pylodictis olivaris*) in lock-chamber samples; and smallmouth bass (*Micropterus dolomieui*), sauger, and saugeye (hybrid between sauger and walleye) in pool samples (Ref. 2.3-20).

Sampling results for the New Cumberland Pool from sources other than ORSANCO indicate similar fish species composition, considering differences in collection methods, sampling locations, season, and other factors that can influence results. Sampling by PFBC in the Pennsylvania reach of the pool, in 1991, yielded 32 species (Ref. 2.3-18). Species found in relatively high numbers in these samples were also abundant in ORSANCO sampling results, and few additional species were noted.

FENOC and its predecessor operating company at BVPS, Duquesne Light, have conducted fish sampling in the BVPS site vicinity since 1970, several times per year. The sampling is typically done in May, July, September, and November. This cumulative effort has resulted in the collection of 72 species and 5 hybrids from the New Cumberland Pool (Ref. 2.3-5, Table 2.8). The long duration of this effort and the variety of sampling methods employed undoubtedly contribute to the relatively high number of species recorded. Since 1980, gizzard shad and emerald shiners have been the most abundant species collected, typically comprising more than 30 percent of the catch. Smallmouth bass, spotted bass, white bass, channel catfish, and sauger are typically the most abundant sport fish in the collections (Ref. 2.3-23).

ORSANCO has identified an increased trend to healthier fish populations in the New Cumberland Pool since the late 1960s on the basis of a statistical analysis of modified index of well-being values computed from sample collection data through 1990 (Ref. 2.3-24, Figure 9). Index values for 1988 – 1990 (last three years of data available) were in the range of 8.6 – 10.4 which, exclusive of other factors, suggests a rating of good to exceptional for the resource (Ref. 2.3-24).

FERC (Ref. 2.3-3, Sections 3.1.4, 3.2.3) provides summary information from a number of researchers regarding the ecology of important fish species in the upper Ohio River, including habitat use and value. Principal habitat, summarized by FERC from U.S. Environmental

Protection Agency (EPA) information for adults of relatively abundant species in the New Cumberland Pool, includes the following:

- Open water (pelagic) habitat: gizzard shad, skipjack herring, emerald shiner, freshwater drum, and white bass;
- River bottom: redhorses, catfish, and sauger; and
- Shallow water: common carp, silver chub, most other minnow and shiner species, smallmouth buffalo, smallmouth bass, crappie, bluegill, and other sunfish.

Backwaters, such as those occurring in low-current areas of island backchannels, in flooded stream mouths, and in dam tailwaters, are noted by FERC (Ref. 2.3-3, Sections 3.1.4, 3.2.3) as particularly important fish habitats in the Ohio River. Backwater areas were noted as providing spawning and nursery areas for a variety of game and forage species. Such species as smallmouth bass, bluegill, and other sunfish are shallow-water, nest-building species that use these areas as spawning and nursery areas. Shallow-water areas associated with islands, particularly backchannel areas, provide habitat for numerous species, including young-of-the-year suckers and a variety of game fish. Dam tailwaters provide spawning habitat for sauger and are of substantial value to the recreational fishery for such species as sauger, white bass, and channel catfish (Ref. 2.3-3, Sections 3.1.4, 3.2.3).

Commercial fishing is prohibited in portions of the Ohio River bordering Pennsylvania, Ohio, and West Virginia, including the New Cumberland Pool (Ref. 2.3-25). Sport fishing in the pool was surveyed in 1992 (Ref. 2.3-26; Ref. 2.3-27), and FERC (Ref. 2.3-3, Section 3.5.4) summarizes recreational fishing information on the pool for earlier years. On the basis of this information, primary sport fishes sought and caught in the pool include black bass; i.e., smallmouth, largemouth, and spotted bass; percids, including sauger, walleye, and saugeye; *Morone,* primarily white bass and "striped bass hybrids," the hybrid of white bass and striped bass (*Morone saxatilis*); catfish, including channel catfish and flathead catfish; common carp; and crappie (*Pomoxis spp.)*. The ODNR, in cooperation with the West Virginia Division of Natural Resources (WVDNR) and the PFBC, maintain the striped bass hybrid sport fishery in the New Cumberland Pool by stocking with fingerlings (Ref. 2.3-19; Ref. 2.3-28).

2.3.1.5 Peggs Run

Peggs Run is a small Ohio River tributary that drains much of the area south of the BVPS site. (Figure 2.1-3) The lower portion of the stream, which runs through the BVPS site, is predominantly an underground culvert channel. The channel begins near the BVPS main access gate and runs approximately 500 feet to its outfall. The outfall is a 15-foot wide concrete and sheet-pile channel located immediately upstream (east) from the BVPS-1 cooling tower. Peggs Run occupies a natural channel south of the BVPS site, consisting of a series of shallow pool, riffle, and run habitats. The substrate in this upstream segment is predominantly cobble intermixed with boulders, gravel, and sand. Upland forest communities border Peggs Run in this area, providing shoreline habitat and overhanging vegetation. The invert elevation of this segment of Peggs Run is sufficiently upgradient to be uninfluenced by water levels in the river (Ref. 2.3-12).

In addition to modifications to its lower reach, Peggs Run has been historically degraded as a result of coal mine drainage in its watershed. At the time of BVPS-2 construction, the substrate of the stream was degraded by oxidized iron floc and supported only limited macrobenthic populations (Ref. 2.1-17, Section 4.3.4). Acid mine drainage to the stream has been reduced since that time and substrate conditions have improved substantially; however, water in the upper reach of the run is reportedly deep red in color during high flow periods, suggesting some continued influence of mine drainage on the stream (Ref. 2.3-31). A 3-year field study of macroinvertebrates in the stream, conducted in 1996 – 1999, indicated that pollution intolerant species are now present in the stream and observed differences in community composition that are likely influenced primarily by differences in substrate rather than water quality (Ref. 2.3-31). In general, the macroinvertebrate assemblage in the downstream segment that flows through the culvert was found to exhibit low diversity and consist predominantly of chironomids and other dipterans, while the assemblage noted in upstream segments, which feature a diversity of natural substrates, was substantially more diverse with a higher proportion of other taxa (e.g., mayflies and caddisflies). The segment of Peggs Run that runs through the culvert is the receiving stream for some stormwater and wastewater discharges from the site. However, these discharges are unlikely to affect, appreciably, habitat conditions in the culvert (Ref. 2.3-31).

2.3.1.6 Entrainment and Impingement Studies

From 1970 to the present, various adult fish and impingement surveys have been performed by BVPS for the site. In the early 1980's, the NRC determined that these studies could be discontinued, but the program was continued through 1995. Fish impingement data and fish sampling results for the years 1980 through 1995 (with the exception of 1986, no report was available) were reviewed. In all years, the number of fish impinged per day was at least an order of magnitude less that what were collected in the limited fish sampling efforts. (Ref. 2.3-65)

From 1976 to 1995, BVPS conducted ichthyoplankton surveys in the main channel of the Ohio River near the intake structure. The NRC determined that these studies could be discontinued in 1980, but the program was continued. Based on the low water withdrawal of the BVPS and the high reproductive capabilities of the predominant species in the area, it was determined that entrainment loss at the BVPS should result in negligible impact on adult fish populations. (Ref. 2.3-65)

BVPS uses closed cycle circulating water systems with continuous overflow. The intake is located at the shore along a typical main stream run of the Ohio River, which is not considered a unique or critical habitat. The incorporation of closed cycle cooling into the facility's operation is considered by the EPA to be the Best Technology Available to mitigate impacts on aquatic resources. (Ref. 2.3-65)

In addition to using the best technology, controlling procedures and best management practices are implemented to ensure there is no impact on the aquatic community in the Ohio River in the vicinity of the BVPS. (Ref. 2.3-65)

2.3.2 Critical and Important Terrestrial Habitats

Phillis Island, the uppermost holding in the Ohio River Islands National Wildlife Refuge, and the small riparian zone wetlands constituting a portion of the northern site boundary bordering the river, both discussed in Section 2.3.1, comprise the only known terrestrial habitats of recognized importance on the BVPS site, transmission lines, or adjacent properties. No other wetlands exist on the BVPS site. Terrestrial habitats on upland areas predominantly consist of upland mixed hardwood forest and scrublands. The upland forest is situated primarily on slopes of the east-west trending ridge, bisected by Peggs Run and SR 168, which comprises a majority of the site property. Scrublands on the site lie mostly on and near transmission corridors, which run between the Beaver Valley Substation to the ridgetop and then, for the most part, parallel the ridge (see Figure 2.1-3).

Descriptions of these vegetation communities and associated wildlife in the mid-1970s, during the early years of BVPS-1 operation, are provided in the BVPS-2 Operating Stage ER (Ref. 2.1-5, Section 2.2.1) and in the BVPS-2 FES (Ref. 2.1-17, Section 4.3.4.1, Figure 4.1). These studies confirmed that the upland communities on the site are characteristic of disturbed wooded and shrubby areas in southwestern Pennsylvania. The upland forest, specifically characterized as early successional or subclimax forest, is composed of several distinctive community types depending on slope and aspect. These include black locust and black cherry (*Prunus serotina*) on the ridge tops, mixed oak and sugar maple (*Acer saccharum*) on east- to southeast-facing slopes, mixed oak and mountain laurel (*Kalmia latifolia*) on south- to southwest-facing slopes, mixed mesophytic forest on north-facing slopes, and American beech (*Fagus grandifolia*)-sugar maple forest in ravines (Ref. 2.1-5, Section 2.2.1). A FENOC reconnaissance-level survey conducted in July 2002 generally confirmed this characterization, although no attempt was made to delineate subtypes (Ref. 2.3-12). Predominant overstory species noted in this upland forest as a whole in the July 2002 survey included sugar maple, black cherry, and northern red oak (*Quercus rubra*). Sugar maple and spicebush (*Lindera benzoin*) are dominant understory species, and pale jewelweed (*Impatiens pallida*), May apple (*Podophyllum peltatum*), and Christmas fern (*Polystichum acrostichoides*) are predominant in the herbaceous layer (Ref. 2.3-12).

Based on results of the July 2002 reconnaissance survey, predominant woody species within the onsite transmission line corridor scrublands included sapling-size black cherry, staghorn sumac (*Rhus typhina*), and blackberry (see Figure 2.1-3). Marginal wood fern (*Dryopterus marginalis*), white snakeroot (*Eupatorium rugosum*), pale jewelweed, and tall goldenrod (*Solidago altissima*) are dominant herbaceous species noted in this community during the survey (Ref. 2.3-12). Persistence of scrublands on these areas is ensured as part of normal corridor maintenance practices, as described in Section 3.1.4. Similar practices are applied as needed to other formerly wooded areas bordering the developed area of the site to maintain visibility for security purposes.

For reasons discussed in Section 3.1.4, FENOC also addresses in this ER relevant environmental impacts of license renewal associated with operation of Duquesne Light's Beaver Valley-Crescent Line 318 and short segments of three other 345-kilovolt (kV) transmission lines connecting to the Beaver Valley Substation, all of which were established to support BVPS-2 operation (see Figures 3.1-1 and 3.1-2). The three short segments, consisting of only two spans each, are situated on or adjacent to the BVPS site. One of these segments, part of FENOC's Beaver Valley-Hanna 345-kV line, lies entirely on developed portions of the site. The latter two segments of FENOC's Beaver Valley-Mansfield No. 1 and Beaver Valley Mansfield No. 2 lines span developed portions of the BVPS site, a forested lower slope north of SR 168, SR 168, and areas maintained as shrub-scrub habitat. Some of this land is bordered by upland forest such as that described above.

Beaver Valley-Crescent Line 318 extends 15.8 miles southeasterly from the Beaver Valley Substation to Duquesne Light's Crescent Substation (Figure 3.1-2). Terrestrial habitats traversed by the corridor consist primarily of upland forest, similar to that described for the BVPS site, and farmland, primarily hay and pastureland, much of which is associated with dairy farms. As noted in Table 3.1-1, the corridor is 150 feet wide for the initial 12-mile segment approaching the Clinton Substation and 85 feet wide for the remaining 3.8 miles into the Crescent Substation. Duquesne Light reported that land use along the line, when it was developed in the mid-1980s, consisted of 10.4 miles of woodland, 2.6 miles of cropland, 0.8 mile of pasture, 0.7 mile of strip mines, 0.02 mile of waterbodies, and approximately 0.9 mile in developed areas (Ref. 2.1-5, Table 3.9-1). Because of the low rate of development in Beaver County in recent years (see Section 2.9), these remain appropriate as general approximations, based on FENOC's review of USGS aerial photography taken in 1995 (Ref. 2.3-32) and field inspections of selected portions of the line. However, the 0.7 mile area indicated as strip mines, apparently corresponding to the terminal segment of the line at the Crescent Substation, is now a reclaimed disposal site for ash from the nearby Phillips Power Station. Vegetation cover at this reclaimed site consists predominantly of grasses, with some forbs; woody vegetation is sparse and scattered. Information from these sources also indicates that the corridor itself consists predominantly of disturbed habitats, including segments that are developed (e.g., road crossings), devoted to agricultural use (primarily hay and pastureland), maintained shrub-scrub habitat, and the reclaimed ash landfill. Relatively undisturbed habitat on the corridor consists of deciduous forest, which remains on some lower slopes of deeper ravines and valleys that are spanned by the line.

Beaver-Valley Crescent Line 318 spans Raccoon Creek and four smaller named streams: Peggs Run; Service Creek (upstream from Ambridge Reservoir) and Raredon Run, both Raccoon Creek tributaries; and Boggs Run, which outfalls to the Ohio River south of the Crescent Substation. Several small headwater tributaries of these named streams are also spanned by the line.

National wetland inventory maps from 1967 to 1983 indicate that two small wetlands exist on or near the corridor: approximately two acres of palustrine forest at the Service Creek span and one or more small areas of riparian emergent wetland at the Raccoon Creek crossing (Ref. 2.3-9). Field reconnaissance by FENOC in May 2003 indicated that palustrine forest at the Service Creek crossing is selectively cleared of large trees but is otherwise undisturbed (spanned). The reconnaissance did not indicate the presence of emergent wetland habitat on or adjacent to the corridor at the Raccoon Creek crossing. The Raccoon Creek floodplain at the transmission line crossing is approximately 1,200 feet wide and consists of cultivated land except for a narrow riparian strip that currently supports a shrub-scrub community within the corridor. A rich, relatively mature deciduous forest occupies bottomlands and valley slope adjacent to the corridor at this location. The transmission line corridor also traverses on or near the western boundary of the Independence Marsh property, which lies north of SR 151 near the Raccoon Creek crossing. Independence Marsh, an 18-acre mitigation wetland, was constructed in 1993 to replace wetlands lost in the expansion of the Pittsburgh International Airport (Ref. 2.3-33).

Several zones along Raccoon Creek and elsewhere in Beaver County are recognized by the Beaver County Planning Commission as areas with high biodiversity, based on a 1993 Natural Heritage Areas Survey (Ref. 2.1-6). One of these zones is located in the general area between Raccoon Creek and Raredon Run. The Beaver Valley-Crescent Line 318 corridor traverses approximately 1 mile of this zone eastward from the Raccoon Creek crossing (see Figure 3.1-2). The Pennsylvania Natural Diversity Inventory (PNDI) has identified special-status plant species, designated at the state level, that have historical occurrence records in this general vicinity, as discussed in Section 2.3.3.

2.3.3 Threatened or Endangered Species

The FWS has listed several species with ranges that include Pennsylvania as threatened or endangered at the federal level or candidates for such listing (Ref. 2.3-34; Ref. 2.3-35), but has not designated any areas in the Commonwealth as critical habitat for listed species (50 CFR 17.95, 50 CFR 17.96). Similarly, threatened, endangered, and candidate species have been designated at the state level under programs administered by the Pennsylvania Game Commission (birds and mammals; Pennsylvania Code, Title 58, Chapter 133), Pennsylvania Fish and Boat Commission (reptiles, amphibians, and fish; Pennsylvania Code, Title 58, Chapter 75); and PDCNR (plants; Pennsylvania Code, Title 17, Chapter 45). FENOC lists in Table 2.3-2 those federally listed and candidate species with historical ranges that include the upper Ohio River or southwestern Pennsylvania, except those presumed to be extirpated in the Commonwealth (e.g., by the Pennsylvania Biological Survey, Ref. 2.3-36, or by PNDI, Refs. 2.3-37 through 2.3-40). FENOC also lists in Table 2.3-2 state-listed and candidate species that are considered to have a potential for occurring on or near the BVPS site, in the New Cumberland Pool, or near the Beaver Valley-Crescent Line 318 transmission line corridor, on the basis of criteria described in the footnote to the table. Table 2.3-2 provides summary information on species status, habitat, and occurrence, which is discussed in the following sections.

2.3.3.1 Aquatic Species

Aquatic species listed in Table 2.3-2 consist of two native freshwater mussels, listed as endangered at the federal level, and nine fish species that are variously designated as endangered, threatened, or candidates for listing at the state level. All of these species are of concern from the standpoint of their actual or potential occurrence in the New Cumberland Pool of the Ohio River.

The two mussel species apparently occurred in the upper Ohio River in the early 1900s. However, neither has been reported from the upper Ohio River since that time as of 2006 (Ref. 2.1-12, Appendix J), nor have the PNDI searches conducted at FENOC's request indicated their likely presence in streams crossed by Beaver Valley-Crescent Line 318 as of 2003 (Ref.

2.3-42; Ref. 2.3-44). Reasons (river impoundment and pollution) for this phenomenon were discussed in Section 2.3.1.3 in the context of the current mussel fauna in the pool. Based on surveys conducted in 2000 in the upper Ohio River and at potentially favorable habitats in the New Cumberland Pool, including Phillis Island and other areas near BVPS (Ref. 2.3-14), the likelihood that these or other federally listed mussel species currently exist near the BVPS site is low. The potential for the establishment of one or more listed mussel species in the New Cumberland Pool in the future is conjectural, but remains a possibility in view of recent evidence for population increases or recolonization for some mussel species in the upper river in recent years, probably attributable to improved water quality, as discussed in Section 2.3.1.3.

All of the fish species listed in Table 2.3-2 have been indicated to FENOC by the PNDI and PFBC as potentially occurring near BVPS as of 2002 (Ref. 2.3-42). FENOC's review of collections from the New Cumberland Pool, described in Section 2.3.1.3, suggests that all of these species occur in the pool, some in relatively high numbers. Pertinent information from the review is provided in Table 2.3-2 and discussed in the following paragraphs.

The silver chub, the only state-endangered species noted by the PNDI and PFBC to have potential for occurrence in the BVPS site vicinity, is reported in ORSANCO collections for 4 of 7 years during the 10-year period from 1992 through 2001, and is reported with a similar frequency in annual monitoring studies conducted by FENOC and Duquesne Light at BVPS during this same period (Ref. 2.3-4). This species was relatively abundant in the ORSANCO collections. Substantial numbers of this species were also collected from the pool by the PFBC in 1991.

Among the state-threatened species listed in Table 2.3-2, skipjack herring and smallmouth buffalo have been frequently present and relatively abundant in recent ORSANCO collections. The latter species has also been frequently collected in the BVPS monitoring program, and several individuals were collected by the PFBC in 1991. Mooneye also has been collected frequently in recent years in both the ORSANCO and BVPS monitoring programs, but was relatively more abundant in the latter. Channel darter and goldeye have been noted infrequently and in low numbers in recent ORSANCO and BVPS collections, although the PFBC collected several individuals of the latter species from the pool in 1991.

Among those species listed in Table 2.3-2 as candidates for listing in the Commonwealth, longnose gar (*Lepisosteus osseus*) and river redhorse (*Moxostoma carinathum*) have been collected infrequently and in relatively low numbers by ORSANCO. However, longnose gar is regularly collected in BVPS annual monitoring, and the PFBC collected substantial numbers of this species in 1991. Brook silverside (*Labidesthes sicculus*), also a state-candidate species, apparently is found infrequently and in small numbers in the New Cumberland Pool.

The PFBC noted that pollution-intolerant species such as mooneye, goldeye, skipjack herring, and river redhorse had increased in the upper Ohio River in years leading up to their 1994 report, consistent with improvements in water quality (Ref. 2.3-18). As noted in Table 2.3-2, most of the special-status species discussed above are notably intolerant of turbidity and siltation which, as with chemical pollutants, are generally recognized to be potentially limiting factors to populations of these species. The continued presence, and in some cases relatively high abundance, of the special-status species represented in these collections generally supports the view that improved conditions in the river are largely responsible for the observed increases in species populations. At the same time, changes in physical habitat that have accompanied impoundment of the river have undoubtedly permanently altered the historical faunal assemblage. Habitat availability in the pool, habitats sampled, and sampling gear employed may contribute to the low numbers of some species that were represented in the collections. Examples include the brook silverside, which prefers quiet water with low turbidity.

TABLE 2.3-2

THREATENED, ENDANGERED, AND CANDIDATE SPECIES *OF POTENTIAL CONCERN TO BEAVER VALLEY POWER STATION LICENSE RENEWAL*[a]

Common Name *Scientific Name*	U.S. Status	PA Status	Habitat/Occurrence[b]
Invertebrates			
Northern riffleshell *Epioblasma torulosa rangiana*	E	E	Large and small streams, preferring runs with bottoms of firmly packed sand and fine to coarse gravel; recent occurrence in PA limited to upper Allegheny River watershed (Ref. 2.3-49; Ref. 2.3-50). As of 2000, no recent documented occurrences in Ohio River downstream as far as Meldahl Pool (Ref. 2.3-14). As of 2006, no PNDI record of observation in lower Allegheny River/Upper Ohio River in PA since 1919 or earlier (Ref. 2.1-12, Appendix J). Not reported by PNDI or PFBC as occurring in the Ohio River or other waterbodies in 2002 and 2003 near the BVPS site or Beaver Valley-Crescent Line 318 (Refs. 2.3-41 through 2.3-44).
Clubshell *Pleurobema clava*	E	E	Small rivers and streams in clean-sweep sand and gravel; has been found buried 2 to 4 inches deep in clean, loose sand. Recent occurrence in Ohio River drainage in PA limited to upper Allegheny River watershed. (Ref. 2.3-51). As of 2002, no documented occurrences in Ohio River downstream as far as Meldahl Pool (Ref. 2.3-14). As of 2006, no PNDI record of observation in lower Allegheny River/Upper Ohio River in PA since 1919 or earlier (Ref. 2.1-12, Appendix J). Not reported by PNDI or PFBC as occurring in the Ohio River or other waterbodies in 2002 and 2003 near the BVPS site or Beaver Valley-Crescent Line 318 (Refs. 2.3-41 through 2.3-44).
Fish			
Silver chub *Macrhybopsis storeriana*	-	-	Previously endagered in Pennsylvania
Skipjack herring *Alosa chrysochloris*	-	-	Previously threatened in Pennsylvania
Goldeye *Hiodon alosoides*	-	-	Previously threatened in Pennsylvania
Mooneye *Hiodon tergisus*	-	-	Previously threatened in Pennsylvania

TABLE 2.3-2 (CONTINUED)

THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BEAVER VALLEY POWER STATION LICENSE RENEWAL[a]

Common Name Scientific Name	U.S. Status	PA Status	Habitat/Occurrence[b]
Fish (continued)			
Smallmouth buffalo *Ictiobus bubalus*	-	-	Previously threatened in Pennsylvania
Channel darter *Percina copelandi*	-	T	Large clean streams and rivers with moderate current and substrate of large rocks, fine gravel, and sand; riffles are used for spawning and summer feeding and deeper, quieter backwaters are used in winter. Primarily found in upper Allegheny River system in PA as of 2007 (Ref. 2.3-53). Identified by PNDI and PFBC as potentially occurring in the Ohio River near the BVPS site in 2002-2003 (Ref. 2.3-41; Ref. 2.3-42). Recent collections include: ORSANCO (1992 – 2001): Collected 2 of 7 years; total 2 individuals. (0.01 percent of catch) BVPS (1992 – 2001): 0 individuals. Initially reported in 1976. One specimen (live) noted in impingement samples in 1983; reported occurrence in impingement samples prior to 1980. PFBC (1991): Not collected ODNR (1993): Not collected
Brook silverside *Labidesthes sicculus*	-	-	Previously candidate taxon in Pennsylvania
Longnose gar *Lepisosteus osseus*	-	-	Previously candidate taxon in Pennsylvania
River redhorse *Moxostoma carinatum*	-	-	Previously candidate taxon in Pennsylvania

TABLE 2.3-2 (CONTINUED)

THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BEAVER VALLEY POWER STATION LICENSE RENEWAL[a]

Common Name Scientific Name	U.S. Status	PA Status	Habitat/Occurrence[b]
Plants			
Small whorled pogonia *Isotria medeoloides*	T	E	Nearly all populations occur in second growth or relatively mature forests; PA populations most abundant on dry east- or southeast-facing hillsides in mixed oak forest on rocky, somewhat acidic soils; only 2 occurrences in PA verified from 1980-2007; known historical occurrence in southwestern PA only in Greene County (Ref. 2.3-54). Specifically reported as not observed during ecological surveys of the BVPS site in 1974 – 1975 (Ref. 2.1-5). Not identified by PNDI as potentially occurring near the BVPS site or Beaver Valley-Crescent Line 318 transmission line corridor in 2002 and 2003 (Ref. 2.3-41; Ref. 2.3-43; Ref. 2.3-45).
Eastern blue-eyed grass *Sisyrinchium atlanticum*	-	-	Previously endangered in Pennsylvania
Tall larkspur *Delphinium exaltatum*	-	E	Found in dry, open southwestern-facing slopes with limestone soils, in rich shaded woods, and on rocky limestone bluffs in 2000-2001 (Ref. 2.3-55; Ref. 2.3-56, page 575). Historical occurrence in southeastern Beaver Co. and Allegheny Co., but no verified occurrences there between 1980 and 2007 (Ref. 2.3-57). Identified by PNDI as potentially occurring near the Beaver Valley-Crescent Line 318 corridor (Ref. 2.3-43).
Purple rocket *Iodanthus pinnatifidus*	-	-	Previously endangered in Pennsylvania
Harbinger-of-spring *Erigenia bulbosa*	-	-	Previously threatened in Pennsylvania

TABLE 2.3-2 (CONTINUED)

THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BEAVER VALLEY POWER STATION LICENSE RENEWAL[a]

Common Name Scientific Name	U.S. Status	PA Status	Habitat/Occurrence[b]
Reptiles			
Eastern massasauga rattlesnake *Sistrurus catenatus*	C	E	Relatively open oldfield and wet meadow habitat with low-lying areas of saturated soil and higher, drier ground nearby, which is found in PA only in relic prairie terrain in western counties. No historical occurrences in Beaver County; historical occurrence in northeastern Allegheny County, but not between 1980 and 2007 (Ref. 2.3-58). However, both counties are south of its range as indicated by Conant (Ref. 2.3-46). This species was not collected or observed in the initial ecological survey conducted at the BVPS site (Ref. 2.1-5, Table 2.2-16) or site reconnaissance conducted in 2002 (Ref. 2.3-12), and little or no wetland habitat suitable for this species exists in the BVPS site vicinity or along the Beaver Valley-Crescent Line 318 corridor. This species was not identified by PNDI or PFBC as potentially occurring near the BVPS site or Beaver Valley-Crescent Line 318 transmission line corridor in 2002 and 2003 (Refs. 2.3-41 through 2.3-45).
Timber rattlesnake *Crotalus horridus*	-	-	Previously candidate taxon in Pennsylvania
Birds			
Bald eagle *Haliaeetus leucocephalus*	T	E	Thrives around bodies of water where adequate food exists and human intrusions and disturbances are limited. PA populations are recovering from effects of the pesticide dichloro-diphenyl-trichloroethane (DDT), the primary reason for the population decline. From 1997 to 1999, the PA nesting population more than doubled to 43 pairs; however, no nesting has been reported in Beaver or Allegheny Counties from 1999 to 2007 (Ref. 2.3-60). Individuals are occasionally observed along the Ohio River at BVPS. Not identified by PNDI as a potential conflict with respect to the BVPS site vicinity or Beaver Valley-Crescent Line 318 transmission line corridor in 2002 and 2003 (Ref. 2.3-41; Ref. 2.3-43; Ref. 2.3-45). In 2002, PA Game Commission (Ref. 2.3-61) indicated that, except for occasional transient individuals, BVPS was not located in an area that is habitat for an endangered or threatened species of bird under their jurisdiction.

TABLE 2.3-2 (CONTINUED)

THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BEAVER VALLEY POWER STATION LICENSE RENEWAL[a]

Common Name Scientific Name	U.S. Status	PA Status	Habitat/Occurrence[b]
			Birds (continued)
Peregrine falcon *Falco peregrinus*	-	E	Historically, nested on high cliffs overlooking river systems. Current nesting sites include high bridges and buildings in cities, a result of recovery efforts that led to de-listing of this species at the federal level. PA populations are slowly recovering from effects of the pesticide DDT, the primary reason for the population decline. Successfully nesting at several sites in PA, including Gulf Tower in downtown Pittsburgh, Allegheny County (Ref. 2.3-62). Not identified by PNDI as a potential conflict with respect to the BVPS site vicinity or Beaver Valley-Crescent Line 318 transmission line corridor in 2002 and 2003 (Ref. 2.3-41; Ref. 2.3-43; Ref. 2.3-45). In 2002, PA Game Commission (Ref. 2.3-61) indicated that, except for occasional transient individuals, BVPS was not located in an area that is habitat for an endangered or threatened species of bird under their jurisdiction.
Short-eared owl *Asio flammeus*		E	Nests on the ground in open country, including reclaimed strip mines; open, uncut grassy fields; large meadows; airports; and, occasionally, marshes. Nesting habitat is extremely limited in PA; intensive agricultural practices render habitats unsuitable. Nesting was documented on reclaimed strip mines in western PA, including Allegheny County (Ref. 2.3-63). Not identified by PNDI as a potential conflict with respect to the BVPS site vicinity or Beaver Valley-Crescent Line 318 transmission line corridor in 2002 and 2003 (Ref. 2.3-41; Ref. 2.3-43; Ref. 2.3-45). In 2002, PA Game Commission (Ref. 2.3-61) indicated that, except for occasional transient individuals, BVPS was not located in an area that is habitat for an endangered or threatened species of bird under their jurisdiction.

TABLE 2.3-2 (CONTINUED)

THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BEAVER VALLEY POWER STATION LICENSE RENEWAL[a]

Common Name Scientific Name	U.S. Status	PA Status	Habitat/Occurrence[b]
Mammals			
Indiana bat *Myotis sodalis*	E	E	Hibernates in winter in communal caves, usually with standing or flowing water, of which nine are known in PA (none in Beaver and Allegheny Counties). Known summer habitat includes maternal colonies behind flaking bark on dead or dying trees along stream or river corridors and upland forests. Primary threat is disturbance to hibernating populations and hibernation sites (Ref. 2.3-64). Not identified by PNDI as a potential conflict with respect to the BVPS site vicinity or Beaver Valley-Crescent Line 318 transmission line corridor in 2002 and 2003 (Ref. 2.3-41; Ref. 2.3-43; Ref. 2.3-45). In 2002, PA Game Commission (Ref. 2.3-61) indicated that, except for occasional transient individuals, BVPS was not located in an area that is habitat for an endangered or threatened species of mammal under their jurisdiction.

[a]Tabulated species consist of:

1. federally designated threatened, endangered, and candidate species reported by the U.S. Fish and Wildlife Service (FWS) for Pennsylvania (Ref. 2.3-34; Ref. 2.3-35) with known historical ranges that include the upper Ohio River or southwestern Pennsylvania, except those considered to be extirpated in PA, e.g., by the Pennsylvania Biological Survey (Ref. 2.3-36) or the Pennsylvania Natural Diversity Inventory (PNDI); Refs. 2.3-37 through 2.3-40); and
2. the following species officially listed as endangered, threatened, or candidates for listing by the Commonwealth of Pennsylvania (Pennsylvania Code, Title 17, Chapter 45; Title 58, Chapters 75 and 133):
    a. species indicated from PNDI searches as having records of occurrence near BVPS, including the Ohio River and Phillis Island (Ref. 2.3-41; Ref. 2.3-42), or the vicinity of the Beaver Valley-Crescent 318 Transmission Line corridor (Refs. 2.3-43 through 2.3-45);
    b. amphibian and reptile species with ranges that include Beaver County or Allegheny County based on Conant (Ref. 2.3-46); and
    c. bird and mammal species indicated by the Pennsylvania Game Commission as having recent records of nesting (birds), hibernals (bats), or occurrences (other mammals) in Beaver County or Allegheny County, PA (Ref. 2.3-47).

[b]Fish survey data from the following sources: ORSANCO Montgomery and New Cumberland Locks rotenone sampling and New Cumberland Pool electrofishing, 1992-2001 (Ref. 2.3-20); BVPS monitoring as reported in BVPS Annual Environmental Reports Nonradiological for 1980-2002 (Ref. 2.3-48) and BVPS-2 Environmental Report - Operating License Stage (Ref. 2.1-5); and Pennsylvania Fish and Boat Commission (PFBC) gill netting, electrofishing, and seining in New Cumberland Pool, 1991 (Ref. 2.3-18.

2.3.3.2 Terrestrial Species

Terrestrial species designated on the federal or state level as threatened, endangered, or candidates for such listing that have been identified as having some potential for occurrence near the BVPS site or Beaver Valley-Crescent Line 318 corridor based on criteria discussed above consist of five plants, two reptiles, three birds, and one mammal (Table 2.3-2). The following discussion highlights relevant information from Table 2.3-2.

Of the five plant species noted in Table 2.3-2, PNDI searches requested by FENOC indicate that eastern blue-eyed grass (*Sisyrinchium atlanticum*), tall larkspur (*Delphinium exaltatum*), purple rocket (*Iodanthus pinnatifidus*), and harbinger-of-spring (*Erigenia bulbosa*), all state-listed plants, have potential for occurrence near Beaver Valley-Crescent Line 318; none were indicated as having historical occurrence records on or near the BVPS site. The single federally listed plant species of concern, small whorled pogonia (*Isotria medeioloides*), is endangered nationwide and extremely rare. No PNDI occurrence records were identified for this species in areas of concern to BVPS license renewal. Only three populations of small whorled pogonia are known to exist in the Commonwealth, none in southwestern Pennsylvania. Information from the Pennsylvania Department of Conservation and Natural Resources (PDCNR) indicates that there are no recent historical records of this species in Beaver and Allegheny Counties.

Some areas in or near the transmission line corridor may be consistent with the habitat affinities of the small whorled pogonia or the four state-listed species noted above. As indicated in Table 2.3-2, the small whorled pogonia, purple rocket, and harbinger-of-spring are found in woodlands; tall larkspur is found in both woodlands and open areas, and blue-eyed grass is found on open ground and in thin woods. However, as indicated in Section 2.3.2, the transmission corridor itself consists predominantly of disturbed habitats. Relatively undisturbed habitat that remains on the corridor consists of forest on some lower slopes of relatively deep ravines and valleys that are spanned by the line (see Figures 3.1-1 and 3.1-2).

Although not indicated on Table 2.3-2, PNDI searches conducted at FENOC's request also indicate potential for occurrence, on or near the BVPS site, of a non-listed plant species of concern, tall tick trefoil (*Desmodium glabellum*) (Ref. 2.3-41; Ref. 2.3-45). This species, which has a tentatively undetermined status in Pennsylvania, was subject to specific search efforts during FENOC's reconnaissance-level surveys of the BVPS site in July 2002, but was not found (Ref. 2.3-12).

Two reptiles, the Eastern massasauga rattlesnake (*Sistrurus catenatus*), a state-endangered species and candidate for federal listing, and the timber rattlesnake (*Crotalus horridus*), a candidate for listing at the state level, may occur in Beaver and Allegheny Counties. Based on information presented in Sections 2.3.1 and 2.3.2, no habitat suitable for the massasauga exists on the BVPS site or along the Beaver Valley-Crescent Line 318 corridor, and the area is well outside the massasauga's normal range. Habitat potentially suitable for the timber rattlesnake may exist along the transmission line corridor, although most of the forested area is relatively accessible, and thus subject to hunting, logging, and other human activities, which reduces the occurrence potential for this species. Neither of these species was observed in ecological studies on the BVPS site in the 1970s or the July 2002 reconnaissance survey.

Of the three bird species listed in Table 2.3-2, the bald eagle (*Haliaeetus leucocephalus*) is the only one currently designated at the federal level. This species is increasing in number nationally as a result of the ban on dichloro-diphenyl-trichloroethane (DDT) use and recovery efforts and is currently proposed for federal delisting. BVPS employees have occasionally observed transient individuals along the Ohio River in the site vicinity in recent years. However, no nests have been noted in Beaver and Allegheny Counties as of 1999, and prospects appear to be low for future nesting on or near the site considering the intensive industrial development and human activity on the New Cumberland Pool. Potential for future nesting along the Beaver Valley-Crescent Line 318 corridor would seem to be limited to areas on or near the Ambridge Reservoir, considering the predominance of woodlands and sparse development there. However, this potential would be influenced by such factors as local food supply and future development on and near the reservoir. The Beaver County Land Use Action Plan does not identify any future land use near the Ambridge Reservoir, but the General Land Use Policy promotes awareness of environmentally sensitive areas and any conflicts that arose would be documented and resolved (Ref. 2.1-6).

The peregrine falcon (*Falco peregrinus*), formerly listed as a federally endangered species, has also recovered dramatically as a result of the ban on the use of DDT and nationwide recovery efforts, which have included successful establishment in urban areas. This cliff-nesting species is unlikely to nest on or near the BVPS site or along the transmission line corridor, given the probable lack of high cliff sites afforded by local topography. As of 2002, nesting birds in western Pennsylvania were limited to downtown Pittsburgh, where the species has been established because of recovery efforts.

No nesting habitat for the Short-eared Owl (*Asio flammeus*) exists on or near the BVPS site; the reclaimed ash disposal site along the transmission corridor near the Crescent Substation is open habitat similar to reclaimed steep mines, so it may have some suitability for nesting. Neither of these bird species was observed during ecological studies on the BVPS site in the 1970s (Ref. 2.1-5, Table 2.2-10).

The Indiana bat (*Myotis sodalist*), a federally endangered species, is the only listed mammal of potential concern based on the screening criteria described in Table 2.3-2. Some potential exists for the occurrence of maternal nesting colonies along forested stream corridors near the BVPS site or transmission lines. However, no hibernation sites are known to exist in either Beaver County or Allegheny County, and no individuals were observed or captured during ecological studies on the BVPS site in the 1970s (Ref. 2.1-5, Table 2.2-10).

2.4 METEOROLOGY AND AIR QUALITY

Pennsylvania's climate is generally characterized as humid continental with the southwestern portion of the state experiencing changeable temperatures and more frequent precipitation than found elsewhere in the state (Ref. 2.4-1). According to the Pennsylvania State Climatologist Office, the average annual precipitation in the city of Pittsburgh is 39.85 inches. In July, the average high temperature in Pittsburgh is 83°F with an average low of 62°F. During January, Pittsburgh experiences an average high of 34°F and an average low of 19°F (Ref. 2.4-2). Prevailing winds are from the west (Ref. 2.4-3).

2.4.1 Onsite Meteorological Program

The present onsite meteorological program began effectively on January 1, 1976. The 500-foot guyed meteorological tower is located approximately 3,600 feet northeast of BVPS-1, as shown in Figure 2.1-3. The base of the tower is at approximately 730 feet above mean sea level (MSL). The meteorological data monitoring system consists of three levels of instrumentation on the 500-foot guyed tower. Wind speed and direction measurements are made at elevations of 35, 150, and 500 feet. Ambient temperature and dew point measurements are made at the 35-foot level. Temperature differential measurements are made between 35 feet and 150 feet (ΔT[150 feet – 35 feet]) and 35 feet and 500 feet (ΔT[500 feet – 35feet]).

Precipitation data are obtained from a ground-level rain gauge located near the base of the tower. The 500-foot guyed tower is situated on a relatively flat plot of land in the Ohio River valley and is enclosed by a fence. The ground surface in the immediate area is composed of slag and dirt. The data recording and signal conditioning equipment were maintained in three separate locations until May 1980. The signal conditioning equipment is located in an environmentally-controlled trailer located near the base of the meteorological tower, within the enclosed fenced area. Strip chart recorders and TermiNet are located in the BVPS-1 control room. On August 15, 1979, a set of strip chart recorders was installed in the meteorological shelter located near the base of the tower. In May 1980, the PDP8 digital computer originally located in the Duquesne Light offices in downtown Pittsburgh was moved to the meteorological equipment trailer at the monitoring site.

Analog data are telemetered directly to the BVPS-1 control room charts. Before May 1, 1980, digital data were transmitted via microwave telemetry to the computer in Pittsburgh where averages were processed at 15-minute intervals. After May 1980, the computer was hard-wired to the meteorological sensors.

2.4.2 Air Quality

The EPA has established National Ambient Air Quality Standards (NAAQS) for six common pollutants: nitrogen dioxide, sulfur dioxide, carbon monoxide, lead, ozone, and particulate matter (PM). The EPA has designated all areas of the United States as having air quality better ("attainment") or worse ("non-attainment") than the NAAQS. Areas that have been re-designated to attainment from nonattainment are called maintenance areas. To be re-designated, an area must both meet air quality standards and have a 10-year plan for continuing to meet and maintain air quality standards and other requirements of the *Clean Air Act*.

BVPS is located in Beaver County, Pennsylvania, which is a nonattainment area for fine particulate matter ($PM_{2.5}$) and part of a seven-county nonattainment area for ozone. Inside Allegheny County, the EPA has designated nonattainment areas for ozone and $PM_{2.5}$ and designated maintenance areas for coarse particulate matter (PM_{10}), sulfur dioxide, and carbon monoxide. The EPA has designated 40 nonattainment and maintenance areas within a 50-mile radius of the BVPS site. Table 2.4-1 lists all maintenance and nonattainment areas within 50 miles of the BVPS site and their classifications (Ref. 2.4-4 and 40 CFR 81.339).

In October 2006, EPA issued a final rule that revises the 24-hour $PM_{2.5}$ standard and revokes the annual PM_{10} standard (71 FR 61144). Nonattainment designations for PM_{10} are not affected by the new rule, but additional nonattainment areas could be designated under the new $PM_{2.5}$ standard.

BVPS has six individual operating permits for its minor air emission sources, including the auxiliary boilers and emergency diesel generators (See Chapter 9 for a more detailed compliance discussion and table of authorizations). Annual emissions, fuel usage, and volatile organic compounds emitted are calculated using BVPS and FENOC procedures. A Title V State-Only Permit application, submitted in 1996, is currently pending with the PADEP. Upon approval, a single operating permit will be issued for all sources previously mentioned and a baghouse periodically used in the BVPS Paint Shop.

There are no mandatory Class I federal areas within the 50-mile radius of BVPS (Ref. 2.4-5). The closest areas to BVPS that are designated in 40 CFR 81.435 as mandatory Class I federal areas, in which visibility is an important value, are the Dolly Sods and Otter Creek wilderness areas. These areas are located more than 50 miles southeast of the site, in the state of West Virginia.

TABLE 2.4-1

NONATTAINMENT AND MAINTENANCE AREAS WITHIN 50 MILES OF BEAVER VALLEY POWER STATION[a]

Area	Designation	Classification
Sulfur Dioxide		
City of Hazelwood (Allegheny County, PA)	Maintenance	NA[b]
Townships of Madison, Mahoning, Boggs, Washington, and Pine (Armstrong County, PA)	Nonattainment	Primary
Cities of Steubenville and Mingo Junction (Jefferson County, OH)	Maintenance	NA[b]
City of Weirton – including Butler and Clay Magisterial Districts (Hancock County, WV)	Maintenance	NA[b]
New Manchester - Grant Magisterial District (Hancock County, WV)	Maintenance	NA[b]
Carbon Monoxide		
City of Pittsburgh (Allegheny County, PA)[c]	Maintenance	NA[b]
Ozone		
Mercer County, PA	Nonattainment	Subpart 1
Greene County, PA	Nonattainment	Subpart 1
Allegheny, Armstrong, Beaver, Butler, Fayette, Washington, and Westmoreland Counties, PA	Nonattainment	Subpart 1
Portage County, OH	Maintenance	NA[b]
Columbiana County, OH	Maintenance	NA[b]
Jefferson County, OH	Maintenance	NA[b]
Stark County, OH	Maintenance	NA[b]
Trumbull County, OH[c]	Maintenance	NA[b]
Belmont County, OH[c]	Maintenance	NA[b]
Mahoning County, OH	Maintenance	NA[b]
Brooke County, WV	Maintenance	NA[b]
Hancock County, WV	Maintenance	NA[b]
Marshall County, WV[c]	Maintenance	NA[b]
Ohio County, WV[c]	Maintenance	NA[b]
Coarse Particulate Matter (PM_{10})		
City of Clairton and 4 boroughs (Allegheny County, PA)[c]	Maintenance	NA[b]
Jefferson County, OH	Maintenance	NA[b]
City of Weirton (Brooke and Hancock Counties, WV)[c]	Maintenance	NA[b]

TABLE 2.4-1 (CONTINUED)

NONATTAINMENT AND MAINTENANCE AREAS WITHIN 50 MILES OF BVPS[A]

Area	Designation	Classification
City of Follansbee (Brooke County, WV)[c]	Maintenance	NA[b]
Fine Particulate Matter ($PM_{2.5}$)		
Allegheny County, PA	Nonattainment	Not Classified
Beaver County, PA	Nonattainment	Not Classified
Butler County, PA	Nonattainment	Not Classified
Washington County, PA	Nonattainment	Not Classified
Westmoreland County, PA	Nonattainment	Not Classified
Township of Taylor South of New Castle City (Lawrence County, PA)	Nonattainment	Not Classified
Monongahela Township (Greene County, PA)	Nonattainment	Not Classified
Elderton Borough, Township of Plumcreek, and Township of Washington (Armstrong County, PA)	Nonattainment	Not Classified
Belmont County, OH[c]	Nonattainment	Not Classified
Jefferson County, OH	Nonattainment	Not Classified
Portage County, OH[c]	Nonattainment	Not Classified
Stark County, OH[c]	Nonattainment	Not Classified
Brooke County, WV	Nonattainment	Not Classified
Hancock County, WV	Nonattainment	Not Classified
Marshall County, WV[c]	Nonattainment	Not Classified
Ohio County, WV[c]	Nonattainment	Not Classified

[a]Source: Ref. 2.4-4, 40 CFR 81.339, 40 CFR 81.336 and 40 CFR 81.349.
[b]Maintenance areas meet air quality standard and classification is not necessary.
[c]A portion of the county is located within the 50-mile area and is designated nonattainment.

2.5 DEMOGRAPHY

In this section, FENOC describes demographic characteristics of the area within 50 miles of the BVPS site. Year 2000 United States census data are used for the population classification determination presented in Section 2.5.1 and the determination of minority and low-income populations described in Section 2.5.2. Census block groups within the 50- and 20-mile radii from a center point midway between the BVPS-1 and BVPS-2 containment buildings are identified using ArcView® geographic information system (GIS) software. Census block groups with greater than 50 percent of their area outside the 50- and 20-mile radii are not included in calculating total population, minority, or low-income estimates.

2.5.1 General Demography

The NRC's GEIS presents a population classification method using degrees of "sparseness" and "proximity" to characterize the remoteness of the area surrounding a site. Sparseness measures population density and city size within 20 miles of a site; proximity measures population density and city size within 50 miles (Ref. 2.5-1, Section C.1.4). The NRC's model for population by sparseness and proximity measures, as presented in the GEIS, is shown below:

Demographic Categories Based on Sparseness

Sparseness		Category
Most sparse	1	Fewer than 40 persons per square mile and no community with 25,000 or more persons within 20 miles
	2	40 to 60 persons per square mile and no community with 25,000 or more persons within 2 miles
	3	60 to 120 persons per square mile or fewer than 60 persons per square mile with at least one community with 25,000 or more persons within 20 miles
Least sparse	4	Greater than or equal to 120 persons per square mile within 20 miles

Source: Ref. 2.5-1, page C-159.

Demographic Categories Based on Proximity

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

Source: Ref. 2.5-1, page C-159.

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

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

Low Medium High

Source: Ref. 2.5-1, page C-6.

FENOC used data from the U.S. Census Bureau's (USCB's) Census 2000 (Ref. 2.5-2) with geographic information system software (ArcView®) to determine demographic characteristics in the BVPS vicinity. There are an estimated 482,634 persons live within 20 miles of the BVPS site, which equates to a population density of 384 persons per square mile. Applying the GEIS sparseness measures, the BVPS site is classified as Category 4 (greater than or equal to 120 persons per square mile within 20 miles). There are an estimated 3,274,451 persons living within 50 miles of the BVPS site, which equates to a population density of 417 persons per square miles within 50 miles. Applying the GEIS proximity measures, the BVPS site is classified as Category 4 (greater than 190 persons per square mile within 50 miles). According to the GEIS sparseness and proximity matrix, BVPS' sparseness Category 4 and proximity Category 4 indicate that the BVPS site is located in a high population area.

All or portions of 12 counties in Pennsylvania are within 50 miles of the BVPS site: Beaver, Allegheny, Washington, Lawrence, Butler, Greene, Fayette, Westmoreland, Armstrong, Clarion, Venango, and Mercer. In Ohio, all or parts of 10 counties are within 50 miles of the BVPS site: Columbiana, Jefferson, Mahoning, Trumbull, Portage, Stark, Carroll, Harrison, Belmont, and Tuscarawas. In West Virginia, all of Hancock, Brooke, and Ohio Counties, as well as the northern portion of Marshall County, are within 50 miles of the BVPS site.

Approximately 82 percent of the BVPS workforce lives in Allegheny and Beaver Counties (see Section 3.4 for workforce description). Table 2.5-1 presents decennial population estimates and growth rates for these counties of interest. Allegheny County is one of the most populous counties in Pennsylvania, with a year 2005 population density of approximately 1,693 persons per square mile. By comparison, Beaver County has a 2005 population density of approximately 409 persons per square mile (Ref. 2.5-3).

The Pittsburgh metropolitan statistical area (MSA) is the 22nd most populous MSA in the United States with an estimated year 2000 census population of 2,358,695. Two other MSAs lie within a 50-mile radius of the BVPS site. The Youngstown/Warren, Ohio, MSA, located approximately 35 miles northwest of the BVPS site, is the 71st most populous MSA in the United States with an estimated year 2000 census population of 594,746. The Canton/Massillon, Ohio, MSA, located approximately 45 miles northwest of the BVPS site, is the 101st most populous MSA in the United States with an estimated year 2000 census population of 406,934 (Ref. 2.5-4).

The city of Pittsburgh, located approximately 25 miles east of the BVPS site, is the largest municipality in both Allegheny County and the 50-mile radius region, with an estimated year 2000 census population of 334,563 (Ref. 2.5-5). Hopewell Township is the most populous municipality in Beaver County, with a year 2000 census population of 13,254 (Ref. 2.5-5). East Liverpool, Ohio, is the largest municipality within 6 miles of the BVPS site, with a year 2000 census population of 13,089 (Ref. 2.5-5a). Table 2.5-2 presents year 2000 census estimated populations for major municipalities in Beaver and Allegheny Counties.

The populations of Allegheny and Beaver Counties are significantly more aged than the national average (35.3 years), with a median age of 39.6 and 40.7 years, respectively. According to USCB estimates, approximately 20.3 percent and 21.2 percent of the year 2000 population are over the age of 62 in Allegheny and Beaver Counties, respectively (Ref. 2.5-5). In 2004, Allegheny County had a birth rate of 10.6 births per 1,000 people and a death rate of 11.6 persons per 1,000 people. In that same year, Beaver County had a birth rate of 9.9 births per 1,000 people and a death rate of 11.6 persons per 1,000 people (Ref. 2.5-3). In general, populations in both counties have steadily decreased over the past 20 years, due primarily to the decrease in manufacturing jobs, particularly in the steel industry. This has caused significant out-migration of younger workers from the area (Ref. 2.1-6, page S-1). Projections by the Pennsylvania State Data Center indicate that populations in the Allegheny and Beaver combined-county area are expected to decrease through 2020 (Ref. 2.5-7).

Beaver County does not host a significant number of migrant workers or seasonal residents. According to the Beaver County Planning Commission, the population of Beaver County and the region, in general, fluctuates little from season to season. There are a few farms in the area that employ migrant labor and no features or attractions that bring seasonal residents in large numbers (Ref. 2.5-8).

TABLE 2.5-1

ESTIMATED POPULATIONS AND GROWTH RATES IN BEAVER AND ALLEGHENY COUNTIES, 1970 TO 2050

	Beaver County		Allegheny County	
Year	Population[a]	Growth Rate (percent)	Population[a]	Growth Rate (percent)
1970	208,418	-	1,605,016	-
1980	204,441	-1.9	1,450,085	9.7%
1990	186,093	-9.0	1,336,449	7.8%
2000	181,412	-4.4	1,281,666	4.1%
2010	168,643	-7.0	1,187,725	7.3%
2020	160,838	-4.6	1,130,284	4.8%
2030	153,439[b]	-4.6	1,075,621	4.8%[b]
2040	146,381[b]	-4.6	1,023,602	4.8%[b]
2050	139,647[b]	-4.6	974,098	4.8%[b]

[a]Population estimates for years 1970, 1980, 1990 from Ref. 2.5-6; for year 2000, from Ref. 2.5-5; for years 2010 and 2020 from Ref. 2.5-7; for years 2030, 2040, and 2050 from equation in footnote b, using rate of growth from previous decade.

[b]Annual percent growth rate in previous decade calculated using the equation $N[t] = N_{[o]} (1+r)^t$ where N is population, t is time in decades, and r is the growth rate expressed as a decimal.

TABLE 2.5-2

ESTIMATED 2000 CENSUS POPULATIONS FOR NOTABLE MUNICIPALITIES IN BEAVER AND ALLEGHENY COUNTIES[a]

Municipality	2000 Population
Allegheny County	
Pittsburgh	334,563
Penn Hills	46,809
Bethel Park	33,556
Mount Lebanon	33,017
Ross Township	32,551
Monroeville	29,349
McCandless	29,022
Shaler	27,757
Plum	26,940
McKeesport	24,040
Beaver County	
Hopewell Township	13,254
Aliquippa	11,734
Beaver Falls	9,920
Ambridge	7,769
Monaca	6,286
Beaver	4,775
Midland	3,137
Shippingport	237

[a]Source: Ref. 2.5-5.

2.5.2 Minority and Low-Income Populations

2.5.2.1 Minority Populations

FENOC used data from USCB's Census 2000 (Ref. 2.5-2) with geographic information system software (ArcView®) to determine minority characteristics in the BVPS vicinity. Census 2000 compiled block group level demographic data for the following minority categories: Black or African American, American Indian or Alaskan Native, Asian, Native Hawaiian or Other Pacific Islander, Other Single Race Minority, Two or More Races, and Hispanic or Latino origin (Ref. 2.5-2). In addition to these groups, NRC guidance also states that the minority population as a whole (aggregate minority category) should be included in the analysis. The aggregate minority percentage is calculated by aggregating all minority individuals in the block group (Ref. 2.5-9, Appendix D). For the BVPS ER minority population determination, FENOC evaluated the six racial minority categories used in the census, along with the Hispanic or Latino ethnicity and the aggregate minority categories as indicated by the NRC.

The NRC guidance (Ref. 2.5-9) specifies that a minority population exists in either of the following cases:

- Exceeds 50 Percent—the minority population of the environmental impact site exceeds 50 percent, or
- More than 20 Percentage Points Greater—the minority population percentage of the impact site is significantly greater (typically at least 20 percentage points) than the minority population percentage in the geographic area chosen for comparative analysis.

A 50-mile radius, drawn from the center point midway between the BVPS-1 and BVPS-2 containment buildings, was used in this analysis to define the area of potential environmental impact. Census block groups with greater than 50 percent of their area located outside the 50-mile radius, as defined above, were not included in the analysis. The 50-mile radius area includes parts of Pennsylvania, Ohio, and West Virginia, and encompasses all or part of 25 counties (see Figure 2.1-1). The geographic area for comparative analysis consists of each county with at least one census block group located within the 50-mile radius. The population demographic data from these counties were added together to derive average regional numbers for both the minority population as a whole and for each minority category for comparison (see Table 2.5-3).

The percentage of each minority group in an individual census block group was calculated using the following equation:

$$[\text{minority group population/total population}] * 100$$

TABLE 2.5-3

MINORITY AND LOW-INCOME POPULATION CENSUS BLOCK GROUPS

State	County	Black or African American	American Indian and Alaska Native	Asian	Native Hawaiian or Other Pacific Islander	Other Single Race	Two or More Races	Hispanic or Latino	Aggregate Minority	Low Income	Total
	Regional Percent[a]	7.1	0.1	0.8	0.03	0.3	1.0	0.9	9.8[c]	11.4	
	Threshold for Minority Population[b]	27.1	20.1	20.8	20.0	20.3	21.0	20.9	29.8	31.4	
State	County	Number of Minority or Low-Income Block Groups in Category									Total
OH	Belmont	1	0	0	0	0	0	0	1	5	7
OH	Carroll	0	0	0	0	0	0	0	0	0	0
OH	Columbiana	1	0	0	0	0	0	0	1	4	6
OH	Jefferson	6	0	0	0	0	0	0	7	7	20
OH	Mahoning	65	0	0	0	2	0	4	67	34	172
OH	Portage	0	0	0	0	0	0	0	0	0	0
OH	Stark	4	0	0	0	0	0	0	4	2	10
OH	Trumbull	21	0	0	0	0	0	0	21	9	51
OH	Tuscarawas	0	0	0	0	0	0	0	0	0	0
PA	Allegheny	183	0	5	0	0	0	0	199	75	462
PA	Armstrong	0	0	0	0	0	0	0	0	1	1
PA	Beaver	7	0	0	0	0	0	0	9	3	19
PA	Butler	0	0	0	0	0	0	0	0	6	6
PA	Clarion	0	0	0	0	0	0	0	0	0	0
PA	Fayette	0	0	0	0	0	0	0	0	0	0

TABLE 2.5-3 (CONTINUED)

MINORITY AND LOW-INCOME POPULATION CENSUS BLOCK GROUPS

State	County	Black or African American	American Indian and Alaska Native	Asian	Native Hawaiian or Other Pacific Islander	Other Single Race	Two or More Races	Hispanic or Latino	Aggregate Minority	Low Income	Total
	Regional Percent[a]	7.1	0.1	0.8	0.03	0.3	1.0	0.9	9.8[c]	11.4	
	Threshold for Minority Population[b]	27.1	20.1	20.8	20.0	20.3	21.0	20.9	29.8	31.4	
State	County	Number of Minority or Low-Income Block Groups in Category									Total
PA	Greene	0	0	0	0	0	0	0	0	0	0
PA	Lawrence	2	0	0	0	0	0	0	2	2	6
PA	Mercer	7	0	0	0	0	0	0	7	6	20
PA	Venango	0	0	0	0	0	0	0	0	0	0
PA	Washington	1	0	0	0	0	0	0	2	6	9
PA	Westmoreland	3	0	0	0	0	0	0	3	5	11
WV	Brooke	0	0	0	0	0	0	0	0	0	0
WV	Hancock	0	0	0	0	0	0	0	0	0	0
WV	Marshall	0	0	0	0	0	0	0	0	0	0
WV	Ohio	2	0	0	0	0	0	0	2	6	10
	Total	**303**	**0**	**5**	**0**	**2**	**0**	**4**	**325**	**171**	

Source: Census 2000 Summary Files 1 (SF1) and 3 (SF3) for Ohio, Pennsylvania, and West Virginia (Ref. 2.5-2; 2.5-11)

[a] Regional percent calculated using the summary data from each county with at least one block group located within the 50-mile radius.

[b] At least 20 percentage points greater than the regional percent.

[c] Aggregate Minority percentage (i.e., 9.8) is less than the total of percentages indicated for racial and ethnic categories (i.e., 10.2). Difference is attributable to inclusion of only those persons in the Hispanic or Latino ethnicity category identified in the census as white Hispanic or Latino (to avoid double-counting).

To calculate the aggregate minority population in an individual census block group, the populations of each of the six minority racial groups (Black or African American, American Indian or Alaskan Native, Asian, Native Hawaiian or Other Pacific Islander, Other Single Race, and Two or More Races) and those persons identifying themselves as white Hispanic or Latino ethnicity designation were added together and used in the above equation. Because Hispanic or Latino ethnicity is not a racial designation and persons identifying themselves as such may be of any race, this population may also be included within the other racial categories. So, only the number of persons identified as white Hispanic or Latino ethnicity was used in the calculation of the aggregate minority population.

Census 2000 data to the block group level from each of the three states located within the 50-mile radius of the BVPS site (Pennsylvania, Ohio, and West Virginia) were analyzed to determine which block groups meet either or both of the above criteria (exceed 50 percent or more than 20 percentage points greater). The 50-mile radius includes 2,796 census block groups. Table 2.5-3 shows the number of census block groups in each county with a minority population and the threshold values for determining if a minority population exists. The threshold values were calculated by adding 20 percentage points to the regional percentages.

There were no census block groups with a minority population of American Indian or Alaskan Native, Native Hawaiian or other Pacific Islander, or Two or More Races within the 50-mile radius of the BVPS site. There were 325 census block groups with an aggregate minority population (see Figure 2.5-1).

For the individual minority categories,

- 303 census block groups had a minority population of Black or African Americans (Figure 2.5-2, Table 2.5-3),

- 5 census block groups had a minority population of Asians (Figure 2.5-3, Table 2.5-3),

- 2 census block groups had a minority population of "other" single race (Figure 2.5-4, Table 2.5-3), and

- 4 census block groups had a minority population of Hispanic or Latino ethnicity (Figure 2.5-5, Table 2.5-3).

- Allegheny County, Pennsylvania, has 183 block groups with a Black or African American minority population; Mahoning County, Ohio, has 65; and Trumbull County, Ohio, has 21. Stark, Jefferson, Columbiana, and Belmont Counties in Ohio; Beaver, Washington, Westmoreland, Lawrence, and Mercer Counties in Pennsylvania; and Ohio County, West Virginia, each has less than 8 block groups with a Black or African American minority population (see Table 2.5-3).

FIGURE 2.5-1

AGGREGATE MINORITY POPULATION

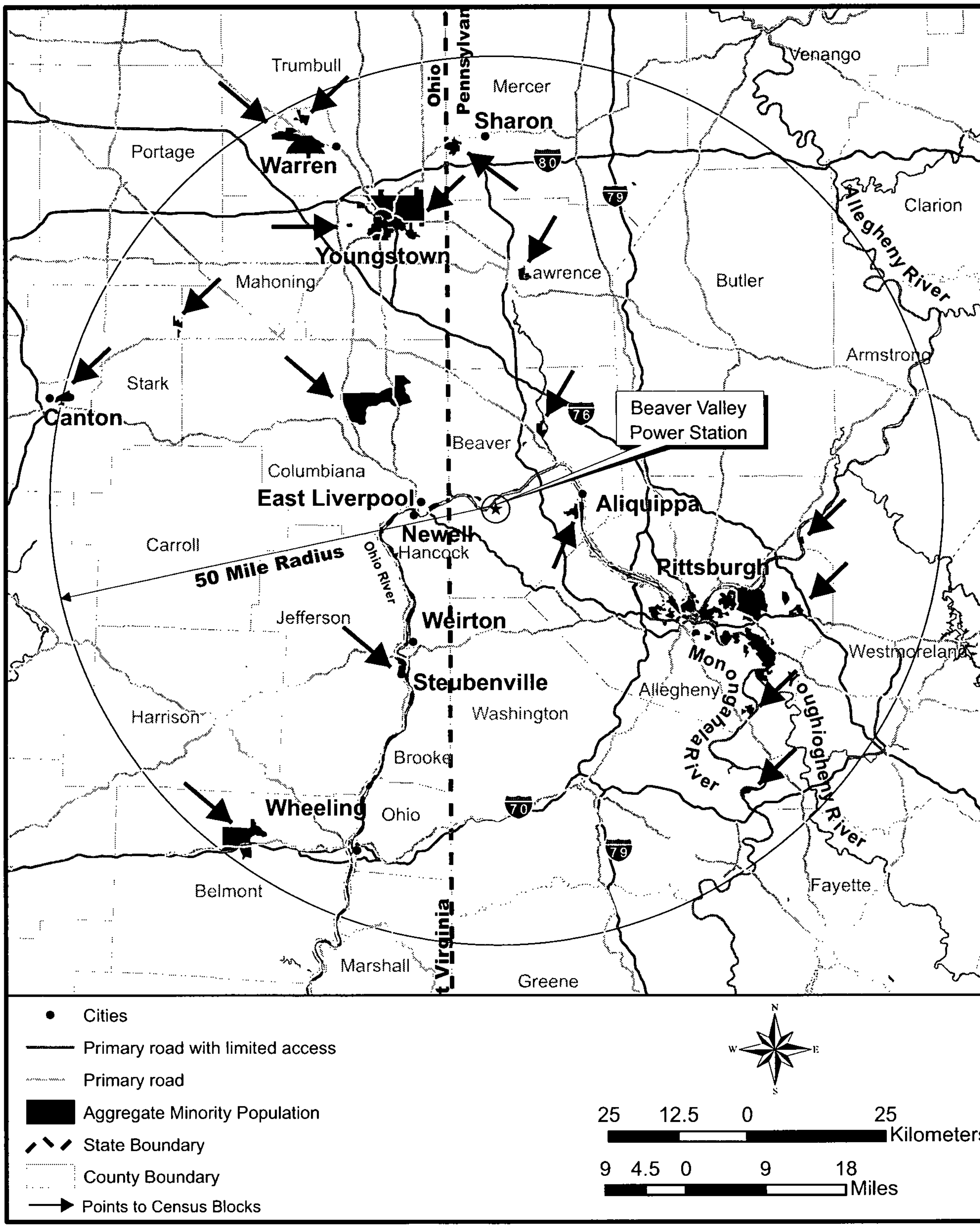


FIGURE 2.5-2

BLACK OR AFRICAN AMERICAN MINORITY POPULATION

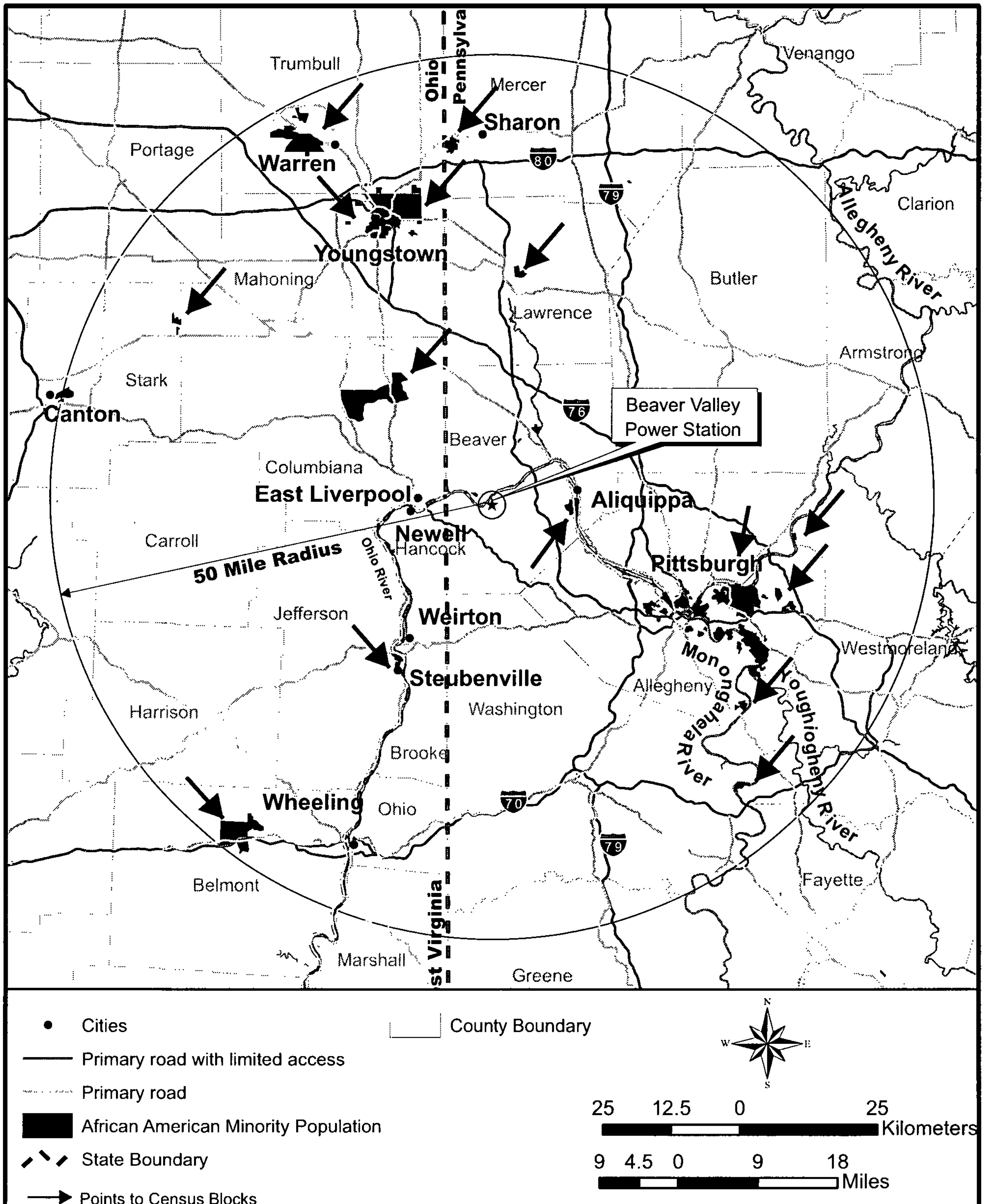
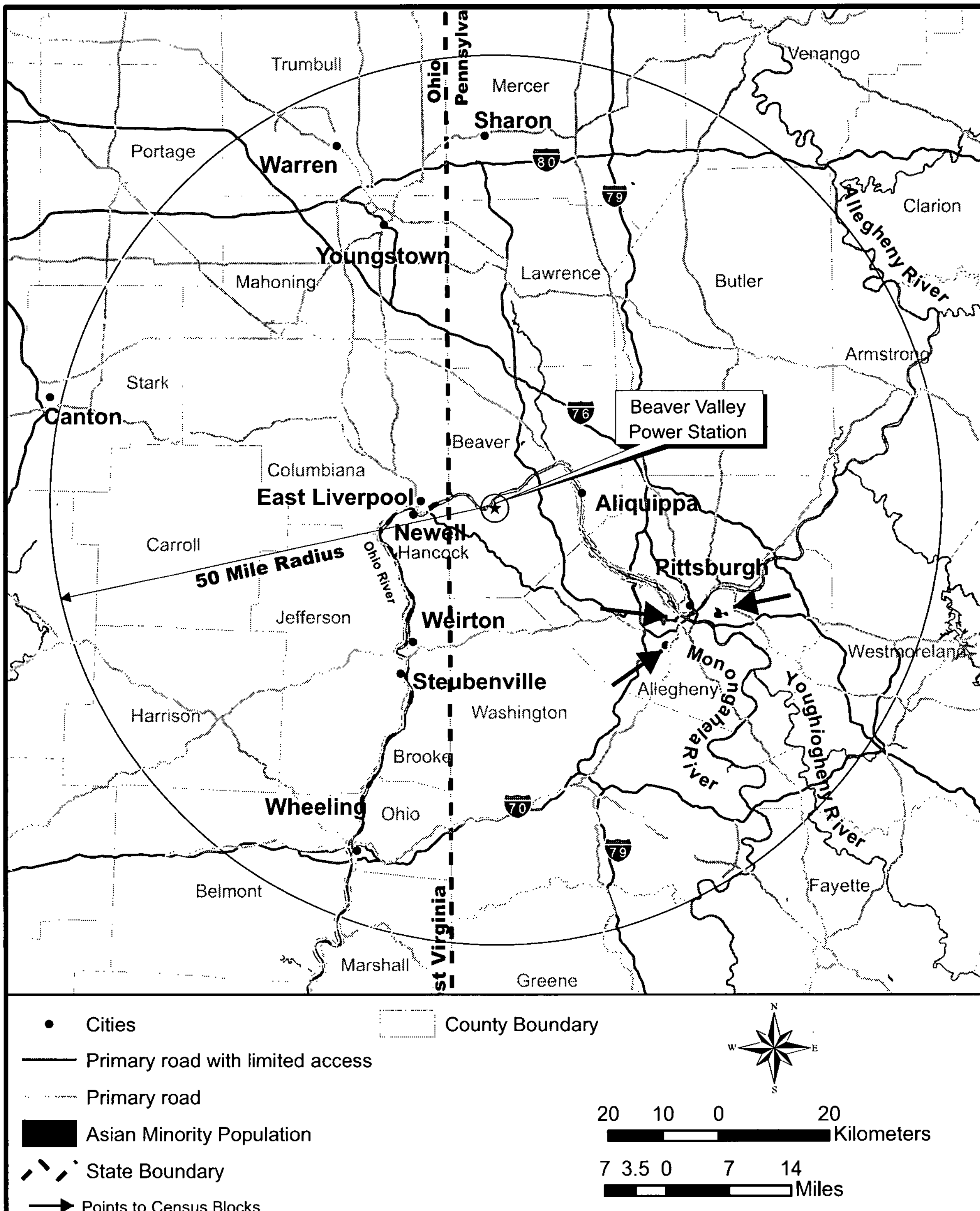


FIGURE 2.5-3

ASIAN MINORITY POPULATION



Allegheny County, Pennsylvania, is the only county within the 50-mile radius to have block groups with an Asian minority population (5 block groups). Mahoning County, Ohio, is the only county within the 50-mile radius of the BVPS site to have an Other Single Race minority population in Census 2000. This racial category was included in Census 2000 to accommodate people who did not identify with the five race categories (White, Black or African American, Asian, Native Hawaiian or other Pacific Islander, and American Indian or Alaska Native) calculated in the census. Two block groups in Mahoning County have a minority population of people of a single race other than those included in the five census categories.

The minority populations in the 50-mile radius are concentrated in areas that are urban centers with high population densities. The greatest number of block groups with aggregate minority populations are located in three counties (Mahoning County, Ohio; Trumbull County, Ohio; and Allegheny County, Pennsylvania) (see Table 2.5-3), in the cities of Youngstown, Ohio; Warren, Ohio; and Pittsburgh, Pennsylvania, respectively. The closest minority population to BVPS is located in the city of Aliquippa, Pennsylvania.

2.5.2.2 Low-Income Populations

FENOC used data from USCB's Census 2000 (Ref. 2.5-11) with geographic information system software (ArcView®) to determine low-income characteristics in the BVPS vicinity. Census 2000 compiled block group level information about low-income households (Ref. 2.5-11). The NRC guidance (Ref. 2.5-9) specifies that a low-income population exists in either of the following cases:

- Exceeds 50 Percent—the percentage of households below the poverty level in the census block group or environmental impact site exceeds 50 percent, or

- More than 20 Percentage Points Greater—the percentage of households below the poverty level in the census block group or environmental impact site is significantly greater (typically at least 20 percentage points) than the percentage of households below the poverty level in the geographic area chosen for comparative analysis.

A 50-mile radius, drawn from the center point midway between the BVPS-1 and BVPS-2 containment buildings, was used in this analysis to define the area of potential environmental impact. Census block groups with greater than 50 percent of their area located outside the 50-mile radius, as defined above, were not included in the analysis. The 50-mile radius encompasses all or part of 25 counties (see Figure 2.1-1). The geographic area for comparative analysis consists of each county with at least one census block group located within the 50-mile radius. The percentages of households below the poverty level from these counties were added together to derive average regional numbers for comparison (see Table 2.5-3).

FIGURE 2.5-4

OTHER SINGLE RACE POPULATION

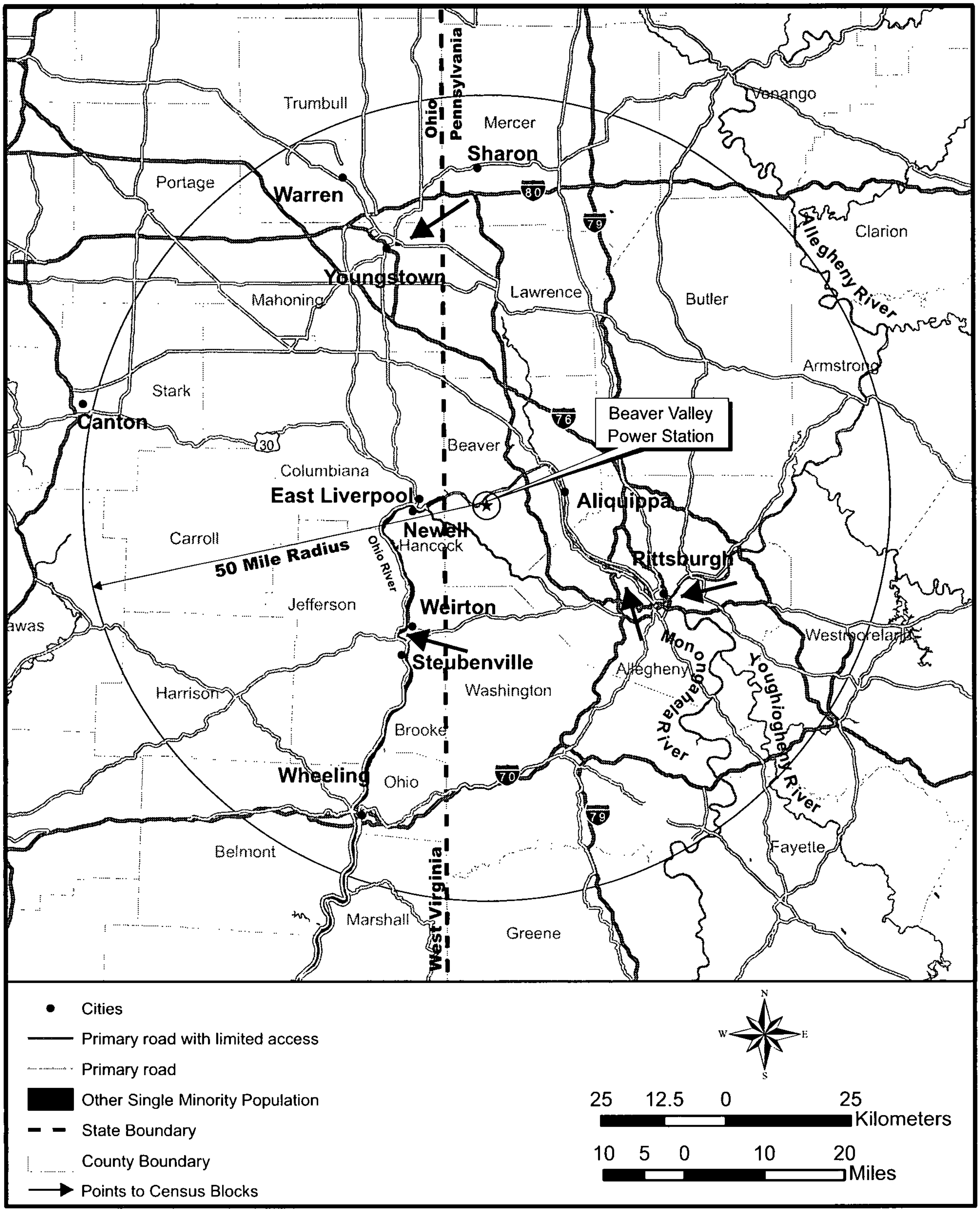
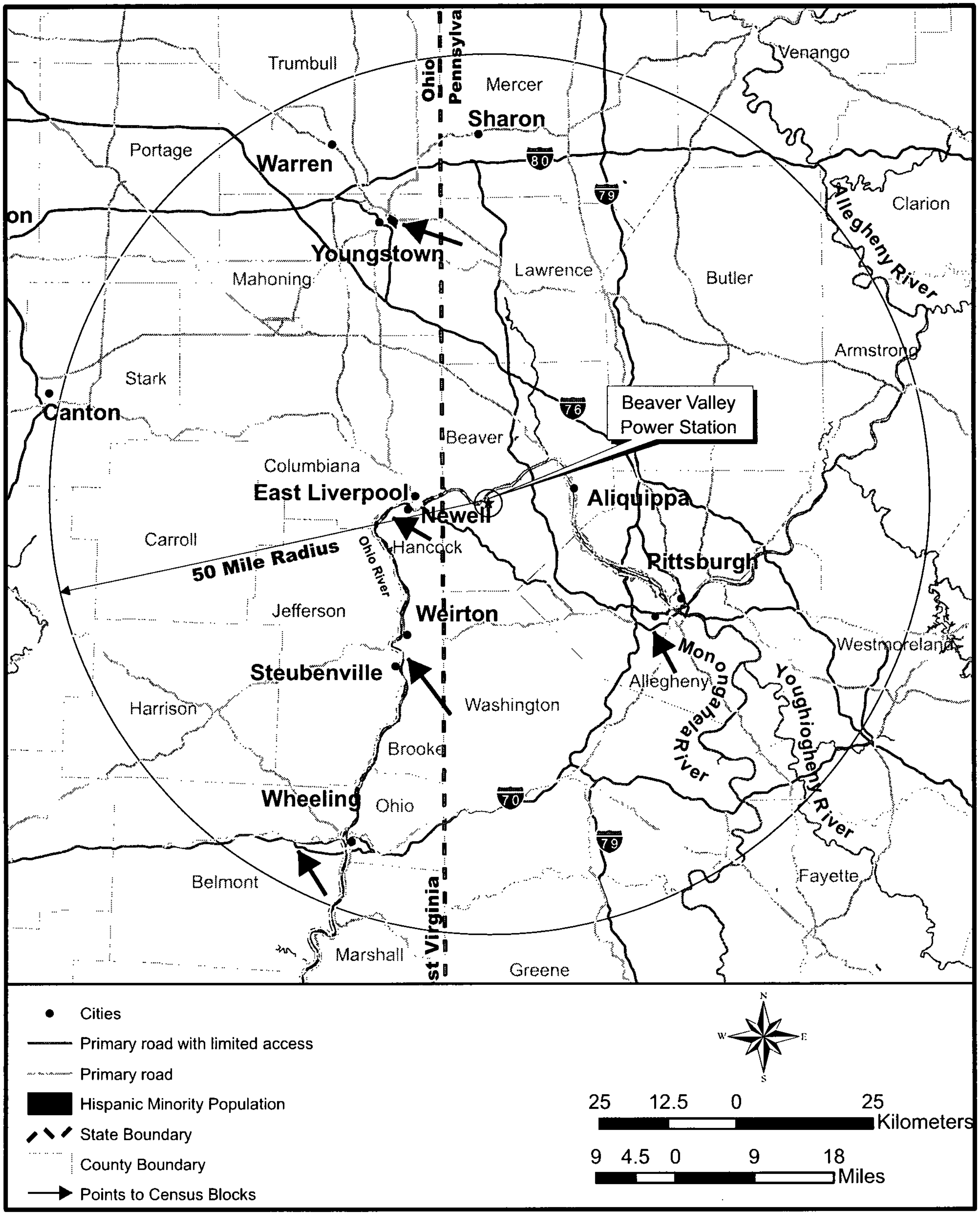


FIGURE 2.5-5

HISPANIC OR LATINO MINORITY POPULATION



Data for both the total number of households and the number of households with an income below the poverty level were obtained for each census block group within the 50-mile radius of the BVPS site. The number of households below the poverty level in each census block group was then calculated as a percentage using the following equation:

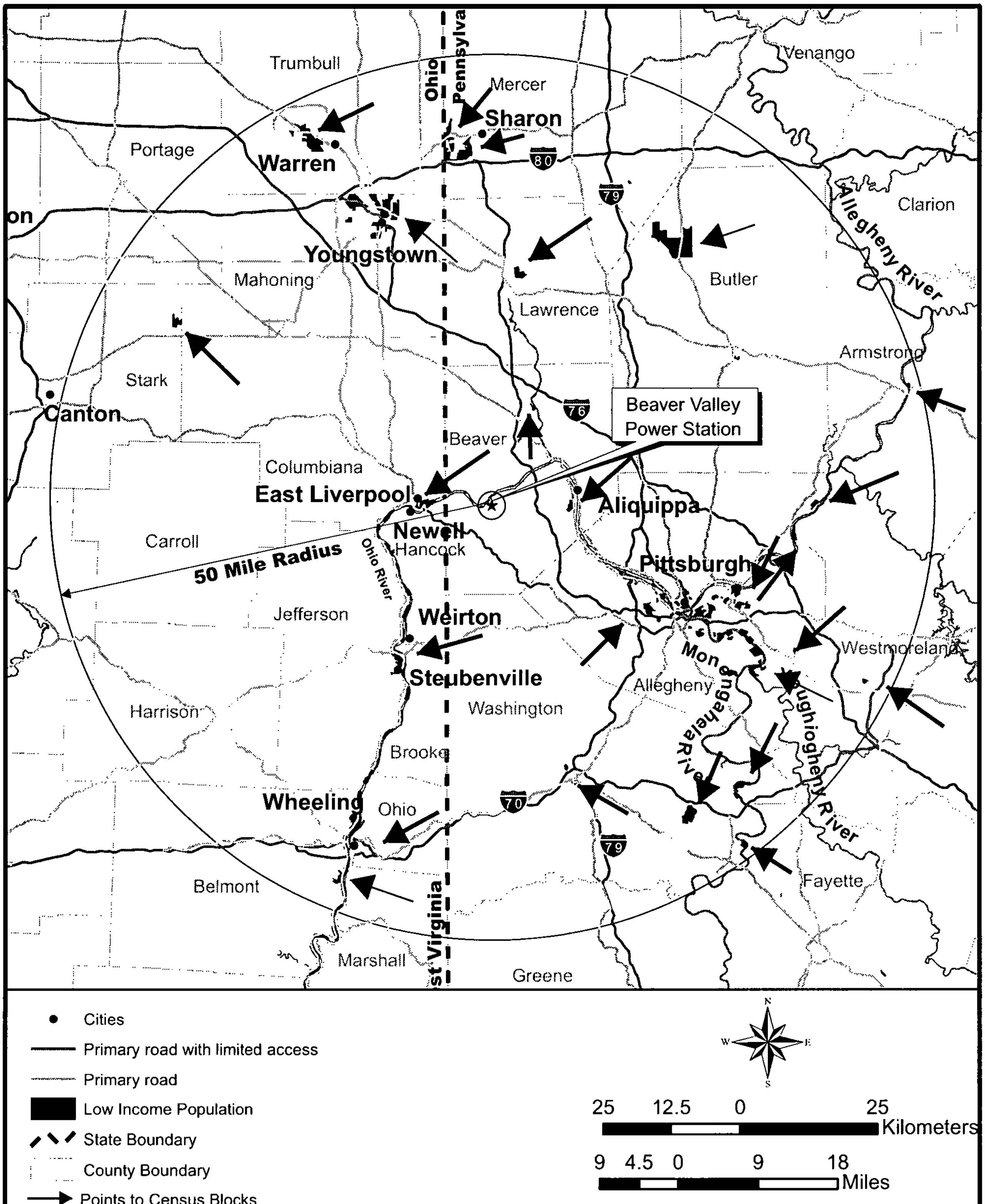
[households below poverty/total households] * 100

Any census block group with a percentage of households below the poverty level greater than 31.4 percent (11.4 regional percent + "20 percentage points greater criterion;" see Table 2.5-3) was considered a low-income population in this assessment.

A total of 171 census block groups within the 50-mile radius of the BVPS site meet the criteria for low-income populations (see Table 2.5-3 and Figure 2.5-6). The majority of the census block groups with a low-income population were located in two counties—Allegheny County, Pennsylvania (75 block groups), and Mahoning County, Ohio (34 block groups). Thirteen other counties–Belmont, Columbiana, Jefferson, Stark and Trumbull Counties in Ohio; Armstrong, Beaver, Butler, Lawrence, Mercer, Washington, and Westmoreland Counties in Pennsylvania; and Ohio County, West Virginia—had census blocks with low-income population, fewer than 10 census blocks in each (see Figure 2.5-6 and Table 2.5-3). The nearest low income population to BVPS is in the East Liverpool, Ohio – Chester, Pennsylvania area.

FIGURE 2.5-6

LOW-INCOME POPULATION



2.6 AREA ECONOMIC BASE

This section focuses on Beaver and Allegheny Counties because 82 percent of the BVPS site workforce resides in these counties. Both counties lie within the Pittsburgh MSA.

An extensive transportation network aids the region's economy. Interstates 70, 76, and 79, as well as several state highways, intersect in the Pittsburgh MSA. This extensive highway network gives the region access to east-west and north-south corridors. Rail lines are an important form of transportation for materials and cargo. Primary freight service is provided by CSX Transportation and Norfolk Southern (Ref. 2.6-1; Ref. 2.6-2). Amtrak also operates a commuter rail terminal in Pittsburgh (Ref 2.6-10). The Ohio, lower Allegheny, and Monongahela Rivers are also significant shipping routes in the BVPS site region. The Port of Pittsburgh District supports over 200 river terminals and barge industry service suppliers, including privately owned public river terminals, throughout 200 miles of commercially navigable waterways in southwestern Pennsylvania. More than 40 million tons of cargo is shipped through the Port of Pittsburgh annually (Ref. 2.6-3). Air traffic is also an important contributor to the regional economy, providing transportation and access to national and international markets. The Pittsburgh International Airport serves almost 10 million passengers on approximately 235,000 flights per year (Ref. 2.6-4).

In 2005, services was the largest employment sector in the Pittsburgh MSA, accounting for 60.6 percent of the non-agricultural employment. Trade accounts for approximately 15.5 percent, while the manufacturing, government, and construction sectors account for approximately 7.6 percent, 9.7 percent, and 5.8 percent, respectively (Ref. 2.6-9).

In the early 1980s, the prominent steel and metals industry in the region suffered a significant decline. As employment levels declined, a proportional decrease in population was observed (see Section 2.5). However, manufacturing remains an important contributor to the regional economy. Of the 10 largest employers in Beaver County, 5 are in the manufacturing sector. The Beaver County Planning Commission projects that prospects are favorable for steady increases in economic growth for the county due to the improved transportation advantages, well-developed community services, attractive amenities, and the county's highly accessible placement within the Pittsburgh MSA (Ref. 2.1-6).

Technology is a growing industry in the Pittsburgh MSA and has helped offset losses in the metals industry. In the year 2004, technology firms represented more than 10.3 percent of all companies in the Pittsburgh region. These firms employ nearly 213,000 individuals and account for 16.9 percent of the area's overall workforce. The $10.8-billion total annual payroll of technology and related companies represents nearly 23.5 percent of the region's wages (Ref. 2.6-6).

Although agriculture is not a significant contributor to area employment, it is an important source of income in the region. According to the 2002 Census of Agriculture, farms in Allegheny and Beaver Counties contributed $9,391,000 and $10,828,000, respectively, to the regional economy (Ref. 2.6-7).

The 2000 population of Beaver County was estimated at 181,412. This represents a 2.5 percent decrease from 1990. The total civilian labor force in Beaver County for June, 2007 was 90,500 of which 86,500 were employed and 4,000 were unemployed. The unemployment rate was 4.5 percent. The average weekly wage for Beaver County in 2006 was $674. This would be equivalent to $16.85 per hour or $35,048 per year, assuming a 40-hour week worked the year around (Ref. 2.6-5).

The 2000 population of Allegheny County was estimated at 1,281,666. This represents a 4.1 percent decrease from 1990. The total civilian labor force in Allegheny County for June, 2007 was 638,100 of which 612,200 were employed and 25,900 were unemployed. The unemployment rate was 4.1 percent. The average weekly wage for Allegheny County in 2006 was $872. This would be equivalent to $21.80 per hour or $45,344 per year, assuming a 40-hour week worked the year around (Ref. 2.6-5).

2.7 TAXES

With the adoption of Senate Bill SB557 by the Pennsylvania Legislature, comprehensive changes were made to the *Public Utility Realty Tax Act* (PURTA). Beginning with the 1998 tax year, utilities' tax bases were changed from the depreciated book value of utility realty to its market value. In the past, FENOC has paid property taxes to the Commonwealth of Pennsylvania for its generating, transmission, and distribution facilities under authority of the PURTA. The PURTA tax receipts from utilities (water, telephone, electric companies, and railroads) were redistributed to the taxing entities within the Commonwealth. Effective January 1, 2000, the Commonwealth of Pennsylvania exempted all power production facilities from paying into the PURTA fund (Ref. 2.7-1). FENOC is now being assessed annual property taxes by Beaver County, Shippingport Borough, and the South Side Area School District. Revenues received by Beaver County support such programs as recreation, public safety, public works, and emergency services (Ref. 2.7-2). Revenues received by the Shippingport Borough support such programs as waste management, public works, and public safety (Ref. 2.7-3).

Table 2.7-1 compares property taxes paid by FENOC for BVPS to the annual total revenue figures for Beaver County, Shippingport Borough, and the South Side Area School District for the years 2001 through 2005. For this period, BVPS property taxes comprised less than 1 percent of the Beaver County total operating budget (Ref. 2.7-4; Ref. 2.7-5; Ref. 2.7-6; Ref. 2.7-7). The percentage of BVPS property tax to the South Side Area School District's operating budget decreased from 15.9 percent in 2001 to 0.07 percent in 2005 (Ref. 2.7-5; Ref. 2.7-6; Ref. 2.7-8; Ref. 2.7-9). In 2002, the Shippingport Borough's operating budget increased by over 200 percent from the previous year, and the BVPS property tax payments increased from 7.6 percent of the budget in 2001 to 16.3 percent in 2002. The tax increase was for only 1 year and was used to pay for the construction of a sewer project. In 2003, BVPS tax payments returned to approximate 2001 levels; however, the sewer project is still in progress and local officials do not expect the total budget for Shippingport Borough to return to pre-project levels until the project is completed (Ref. 2.7-4; Ref. 2.7-5; Ref. 2.7-3; Ref. 2.7-10).

The amount of future property tax payments for BVPS-1 and BVPS-2 and the proportion of those payments to the operating budgets of Beaver County, South Side Area School District, and Shippingport Borough are dependent on future market value of the units, future valuations of other properties in these jurisdictions, and other factors. FENOC assumes that the values presented in Table 2.7-1 are substantially representative of conditions that would exist in the license renewal terms of the units.

TABLE 2.7-1

PROPERTY TAX PAID FOR BEAVER VALLEY POWER STATION; OPERATING BUDGETS OF BEAVER COUNTY, SOUTH SIDE AREA SCHOOL DISTRICT, AND SHIPPINGPORT BOROUGH; 2001-2005

Year	Property Tax Paid for BVPS	Operating Budgets	Percent of Operating Budgets
		Beaver County[a]	
2001	$976,792	$244,370,783	0.4%
2002	$1,741,485	$235,263,817	0.7%
2003	$1,076,636	$241,100,315	0.004%
2004	$439.222	$249,006,040	0.002%
2005	$600,900	$255,367,610	0.002%
		South Side Area School District[b]	
2001	$2,436,363	$15,069,313	15.9%
2002	$2,131,723	$15,550,625	13.7%
2003	$2,331,567	$17,702,191	13.2%
2004	$1,398,796	$18,650,177	0.08%
2005	$1,397,142	$19,020.817	0.07%
		Shippingport Borough[c]	
2001	$71,299	$935,025	7.6%
2002	$508,463	$3,110,025	16.3%
2003	$68,575	$3,879,405	0.02%
2004	$27,976	$5,041,575	0.01%
2005	$27,946	$4,532,305	0.01%

[a]Source: Ref. 2.7-4; Ref. 2.7-5; Ref. 2.7-6; Ref. 2.7-7
[b]Source: Ref. 2.7-5; Ref. 2.7-6; Ref. 2.7-8; Ref. 2.7-9
[c]Source: Ref. 2.7-4; Ref. 2.7-5; Ref. 2.7-3; Ref. 2.7-10

2.8 SOCIAL SERVICES AND PUBLIC FACILITIES

2.8.1 Public Water Supply

This discussion of public water systems focuses on Beaver and Allegheny Counties because approximately 82 percent of the BVPS site workforce resides in these counties (see Section 3.4 for workforce description). Local municipalities and private water companies provide public potable water service to residents who do not have individual onsite wells. According to USCB estimates, approximately 98 percent of Allegheny County households and 80 percent of Beaver County households obtain water from water supply systems owned by the public (e.g., municipalities) or private companies (Ref. 2.8-1). These providers are subject to regulation under the *Federal Safe Drinking Water Act*, as implemented by the Pennsylvania Department of Health.

Thirty-seven primary community water systems reportedly produce potable water for direct sale in Beaver County. An additional eight community water systems are consecutive community water systems, purchasing water from primary systems for resale. Together, these 35 systems service approximately 144,500 residents in Beaver County. Source water for 24 of the primary systems is obtained from groundwater, while 3 systems rely on surface water. Beaver Falls Municipal Authority is the largest water purveyor in the county, with over 17,000 connections (Ref. 2.1-6a). Demand averages between 6 and 8 mgd, and the combined capacity of the system's two water plants is 16 mgd. Source water is obtained from the Beaver River (Ref. 2.8-2) (see Figure 2.1-2).

The Ambridge Water Authority and the Aliquippa Municipal Water Authority are the only two other major water systems in Beaver County with more than 6,500 connections. The Ambridge Water Authority has approximately 7,300 connections and services the Ambridge Borough and surrounding areas. Water demand on the Ambridge Water Authority averages 5 mgd, and the capacity of the water plant is 7 mgd. Source water is obtained from the Ambridge Reservoir (Ref. 2.8-3) (see Figure 2.1-2). The Aliquippa Municipal Water Authority has approximately 7,500 connections and services Aliquippa Borough and surrounding areas. Water demand on the Aliquippa Municipal Water Authority averages 2 mgd, and the capacity of the water plant is 4 mgd. Source water is obtained from groundwater wells in the alluvial aquifer near the Ohio River (Ref. 2.8-4).

The BVPS site acquires potable water from the Midland Water Authority. Current BVPS site usage averages 1.3 million gallons per month (an average of approximately 44,000 gpd). The Midland Water Authority services nearly 2,200 connections in Midland, Shippingport, and Ohioville. Water demand averages 2.9 mgd, and the water treatment plant has a permitted capacity of 5 mgd. Source water is obtained from the Ohio River (Ref. 2.8-5).

The Pittsburgh Water Authority is the largest water purveyor in Allegheny County with approximately 83,000 connections in the city of Pittsburgh and surrounding communities. Water demand averages 70 mgd, and the water treatment plant has a total capacity of 117 mgd (Ref. 2.8-14). Source water is obtained from the Allegheny River (Ref. 2.8-6).

The Wilkinsburg-Penn Water Authority serves approximately 46,000 connections in western Allegheny County. Water demand averages 23 mgd, and the water treatment plant has a total capacity of 40 mgd. Source water is obtained from the Allegheny River (Ref. 2.8-7).

The West View Water Authority serves approximately 50,000 connections in 29 different communities. Water demand averages 25 mgd, and the water treatment plant has a total capacity of 40 mgd. Source water is obtained from the Ohio River and alluvial aquifer groundwater wells (Ref. 2.8-8).

FENOC did not identify any reasonably foreseeable new large water users in the area as a result of information gathering efforts for this section, Section 2.9 (Land Use), or Section 5.0 (New and Significant Information).

2.8.2 Transportation

Road access to the BVPS site is via SR 168, a two-lane paved road, near the intersection with SR 3016 at the Shippingport Bridge. The PDOT has a right-of-way across the eastern end of the BVPS site on which a portion of SR 168 is located, including the southerly approach to the Shippingport Bridge. SR 168 follows Peggs Run from the southwest before turning northward, crossing the Shippingport Bridge, and joining SR 68 (see Figure 2.1-3).

Employees commuting to and from work enter and leave the BVPS site via SR 168, which provides access from the southwest and north. Connecting routes generally used are SR 68 northward, and SR 3016, a connector to SR 18, eastward. Green Garden Road is generally used as a connecting route between SR 18 and SR 60. Each of these major commuting routes is a paved two-lane roadway, except for SR 60, a divided, four-lane, limited-access highway (see Figure 2.1-2).

The PDOT does not maintain level-of-service designations for roadways. Counts determining the average number of vehicles per day are available for selected routes. SR 18 and SR 68 are two of the major north-south commuting routes in Beaver County. The Beaver County Planning Department classifies SR 18 as an urban collector near the BVPS site, while SR 68 is classified as a rural principal arterial roadway. Traffic volumes on SR 68 and SR 18 are much smaller on the segments near the BVPS site compared to the segments in the eastern portions of Beaver County. Green Garden Road, SR 3016, and SR 168 are classified as minor arterial roads. Table 2.8-1 lists commuting routes to the BVPS site, roadway classifications, and average annual daily traffic (AADT) volume values, as determined by the Beaver County Planning Department. The AADT values represent traffic volumes for a 24-hour period factored by both day of week and month of year. Traffic volumes on these routes have generally declined since BVPS-2 came on line (Ref. 2.8-17).

The Beaver County Planning Department has identified several segments of roadway in Beaver County that are deficient due to limited traffic capacity and the physical condition. These identified congested road segments are largely in densely developed and populated areas in

TABLE 2.8-1

MAJOR COMMUTING ROUTES IN THE BVPS VICINITY AND 2004 AVERAGE TRAFFIC VOLUMES

Roadway	Average Annual Daily Traffic Volumes[a,b] (Vehicles Per Day)	Road Classification[c]
SR 168		
• From U.S. 30 to the Shippingport Bridge	2,900-4,900	Urban/rural minor arterial
• From Shippingport Bridge to convergence with SR 68 (Midland Beaver Road)	9,000	Urban other principal arterial/urban minor arterial
SR 3016 (Shippingport Road/Green Garden Road)		
• From SR 168 to SR 18 (Frankfort Road)	6,500	Urban/rural minor arterial
• From SR 18 to SR 3021 (Patterson Road)	4,700	Rural/urban minor arterial
• From SR 3021 to SR 60	6,500 to 8,700	Rural/urban minor arterial
SR 18 (Frankfort Road)		
• From SR 3016 to SR 3010 (Holt Road)	6,800	Urban minor arterial
• From SR 3010 to SR 3019 (Raccoon Creek Road)	7,500	Urban minor arterial
• From SR 3019 to SR 60	9,100	Urban other principal arterial
SR 68		
• From SR 168 to SR 4034 (Wolf Run Road)	5,500	Urban other principal arterial/rural principal arterial – other
• From SR 4034 to SR 4032 (Engle Road)	7,900	Rural principal arterial – other
• From SR 4032 to SR 4037 (Barclay Hill Road)	9,800	Rural principal arterial – other
• From SR 4037 to SR 60	11,000	Rural principal arterial – other

[a]Ref. 2.8-15
[b]Average daily traffic volumes fall within the given range for the indicated road segment.
[c]Ref. 2.1-6
SR = state route
U.S. = United States

Aliquippa, Ambridge, and other river communities in Beaver County east of SR 68. By comparison, commuting routes to the BVPS site are located in more rural areas and are less congested. Beaver County has also earmarked several segments of major commuting routes for maintenance and improvement, including SR 18 and SR 68 (Ref. 2.1-6).

2.8.3 Education

This section focuses on schools in Beaver and Allegheny Counties because 82 percent of the BVPS site workforce resides in these counties. Both counties lie within the Pittsburgh MSA.

Beaver County has 57 pre-kindergarten through 12 (PK-12) schools (Ref. 2.8-9). According to the Pennsylvania Department of Education (PDOE) total public school enrollment for the 2005 – 2006 school year was 30,080 and the projects that enrollment will decline by about 10.6 percent for the 2015-2016 school year (Ref. 2.8-10). Allegheny County has 322 PK-12 schools (Ref. 2.8-9). Total enrollment for the 2005-2006 school year was 163,772 and the PDOE projects enrollment will decline by about 16.7 percent for the 2015-2016 school year (Ref. 2.8-11).

While Pennsylvania does not currently have mandated student to teacher ratios, this information can be tracked for each county. The 2004-2005 average student to teacher ratio for schools in Beaver County is 16.1 and ratio for schools in Allegheny County is 14.3 (Ref. 2.8-9). The average student to teacher ratio for the State of Pennsylvania is 15.1 and the national average is 15.8 (Ref. 2.8-12).

During the 2004-2005 academic session Allegheny and Beaver Counties expended $13,246 and $11,039 per student, respectively (Ref. 2.8-16). During the period 2000 to 2003, total expenditures in Pennsylvania increased an average of 4.6 percent per year from $8,981 to $10,233 per student (Ref 2.8-17).

2.9 LAND USE PLANNING

In the Commonwealth of Pennsylvania, local governments provide services such as police and fire protection, roads and highways, public sewer and water facilities, parks and open space, planning and zoning, and social services. Counties are the next level of government below the Commonwealth and are subdivided into municipalities such as cities, boroughs, and townships. All land within the Commonwealth is incorporated.

The Commonwealth authorizes counties to prepare and adopt comprehensive growth management plans characterizing current conditions and setting standards, policies, and goals for land development. Municipalities are authorized, but not required, to develop these plans as well. However, land-use regulations—such as zoning and subdivision and land development controls—are enacted, administered, and enforced by local municipalities under the legal framework of the Pennsylvania Municipalities Planning Code. Zoning ordinances are used by local governments to regulate and guide development.

This section focuses on Allegheny and Beaver Counties because 82 percent of the BVPS site workforce resides in these two counties and because FENOC pays BVPS property taxes to three jurisdictions in Beaver County: the County; Shippingport Borough; and the South Side Area School District (see Section 3.4 for workforce description).

Comprehensive planning is in various stages in the two counties. There are 54 municipalities in Beaver County (Ref. 2.1-6) and 131 in Allegheny County (Ref. 2.9-1). The majority of municipalities in both counties have developed zoning, subdivision, and other land-use ordinances to regulate development and growth and some have developed comprehensive plans (Ref. 2.1-6; Ref. 2.9-1). A comprehensive plan was adopted by Beaver County on December 29, 1999 (Ref. 2.1-6). Allegheny County does not yet have a plan in place, although the Commonwealth of Pennsylvania has mandated that it do so (Ref. 2.9-1; Ref. 2.9-2). A draft of the Allegheny County Comprehensive Plan is planned for Summer 2007 completion and a final plan is expected in Fall 2007 (Ref. 2.9-4). FENOC has not surveyed the 185 municipalities in Beaver and Allegheny Counties as to the existence of any growth-control measures that would restrict the development of residential housing. However, county-level planning documents encourage development in areas that can be served by existing infrastructure, while preserving open space and environmentally sensitive areas (Ref. 2.1-6).

As stated in Section 2.5, Allegheny County is one of the most populated counties in Pennsylvania with a 2000 population of 1,281,666. Beaver County had a 2000 population of 181,412. Due to the high population of the area, NRC does not require housing and rental market information. The following data are provided for general information to give an overview of housing in the area.

According to year 2000 USCB estimates, there are 583,646 and 77,765 housing units in Allegheny and Beaver Counties, respectively. Over 60 percent of these units in both counties are single family, detached homes. The median value of the homes in Allegheny County is $84,200; the median for Beaver County is $85,000. The average rent in both counties is about $500 per month (Ref. 2.9-5).

In 2000, approximately 6.7 percent and 8.0 percent of the total available housing units are vacant in Beaver and Allegheny Counties, respectively (Ref. 2.5-5). The USCB estimates indicate a very low number of seasonal use housing units (344, or 0.4 percent of total housing units) in the county (Ref. 2.5-5).

In 2003, the Allegheny County Homeless Alliance, a private-public partnership formed with the help of the Allegheny County Bureau of Hunger and Housing Services, created a 10-year plan to end homelessness in the county. Based upon the identified needs and areas, the Alliance has defined actions to be taken over the next 10 years to realize the plan. Among these action steps are to develop 1,000 new units of housing, preserve and maintain current low-income housing, and establish a fund to develop 15,000 housing units for low-income individuals/families. This will be developed on the state and local level (Ref. 2.9-6).

The Beaver County Planning Commission estimates that forest land accounts for 49.5 percent (140,840 acres) of all land in Beaver County, while agricultural land accounts for 26.2 percent (73,892 acres). Forested lands are prevalent in western Beaver County. Residential lands account for 15.5 percent (44,050 acres), while industrial, commercial, and other nonresidential urban land uses account for only 4.1 percent of the County's land area. Included in these industrial lands are brownfield sites of former steel manufacturing operations, including sites along the Ohio River. Much of the developed land in Beaver County is located within the older river communities along the Ohio and Beaver Rivers, although these areas are declining in population and economic activity. County planning officials expect continued growth in eastern and northern Beaver County areas bordering Allegheny and Butler Counties. The area east of SR 60 has experienced significant growth in recent years, spurred in part by the location of the Pittsburgh International Airport in western Allegheny County. Significant growth is not expected in areas west of SR 60. Planning officials believe limited transportation facilities, steep topography, lack of public sewer services and infrastructure, and public sentiment will limit development in existing rural areas in western Beaver County (Ref. 2.1-6).

Using satellite imagery, the Southwestern Pennsylvania Commission estimates that forest land accounts for 49.4 percent (235,547 acres) of all land in Allegheny County, while residential land accounts for 24.8 percent (118,220 acres). Agricultural and pasture lands account for 11.5 percent (54,767 acres), while industrial, commercial, and other nonresidential urban land uses account for 3.2 percent (14,900 acres) of the county's land area (Ref. 2.9-3). The developed land centers in and around the city of Pittsburgh. County planning officials do not anticipate any significant changes to existing land use (Ref. 2.9-1).

2.10 HISTORIC AND ARCHAEOLOGICAL RESOURCES

The National Park Service (NPS) indicates that 20 properties in Beaver County, Pennsylvania, nine properties in Hancock County, West Virginia, and 44 properties in Columbiana County, Ohio, are listed on the National Register of Historic Places (Ref. 2.10-1; Ref. 2.10-2; Ref. 2.10-3). Of these, the following three properties are located within 6 miles of the BVPS site: the USACE's Merrill Lock No. 6, located approximately 5 miles east of BVPS in Industry; the Beginning Point of the U.S. Public Land Survey, located approximately 5 miles west of the BVPS site on the Pennsylvania/Ohio border; and the David Littell House, located approximately 6 miles south of BVPS on SR 18. None of these sites are close enough to BVPS to be potentially affected by normal plant operations.

The Pennsylvania Historical and Museum Commission, Bureau of Historic Preservation (PBHP), the State Historic Preservation Office (SHPO) for Pennsylvania, issues lists of properties in Pennsylvania that are considered by PBHP to be eligible for inclusion on the National Register of Historic Places, regardless of whether the properties have been officially designated by NPS as eligible for such listing (Ref. 2.10-4). PBHP listed five such properties located within 6 miles of BVPS. These consist of four properties across the Ohio River from BVPS (Lockkeepers' House, in Industry; Midland Carnegie Library, Midland High School and J.R. Mitrovich Property, all in Midland), and the decommissioned SAPS facility, located on the BVPS site (Ref. 2.10-6a). The three properties across the Ohio River and the one property to the south are not close enough to BVPS to be affected by normal plant operations.

FENOC provided specific information about SAPS to PBHP for consideration in its review of potential impacts on historical resources resulting from BVPS license renewal (Attachment B, Item B.14). PBHP's conclusion from its review, communicated to FENOC in March 2004 (Attachment B, Item B.15), indicates that SAPS is not a National Register-eligible property. Since that time, several of the remaining structures on the SAPS property were demolished. Two buildings, a guardhouse, and the training and test building, were removed to accommodate the security perimeter expansion of 2004. The SAPS warehouse has also been removed and a completely new structure was constructed at the same location. The western end of the new structure (approximately 75 percent of the total square footage) is used for long-term equipment storage. The eastern end of the new structure is a waste management area. The two areas are physically separated by walls, dikes, etc.

FENOC's review of NPS and PBHP listings (Ref. 2.10-1, 2.10-4) and correspondence with PBHP (Attachment B) indicate that no properties listed on the National Register of Historic Places or recognized as eligible for such listing are located on or near transmission corridors addressed in this ER.

The FES for BVPS-1 noted only one known archaeological site near BVPS, an Indian village site near the abandoned Shippingport ferry docks on the south bank of the Ohio River, about 0.5 mile upriver from the BVPS site (Ref. 2.10-5). This Indian village site has been listed by the Anthropology Center of the Carnegie Museum of Pittsburgh. However, the FES also indicates that almost every major floodplain area along this stretch of the Ohio River was the site of a prehistoric Indian village at one time or another, going back many thousands of years. The FES indicates on the basis of review by the Pennsylvania Historical and Museum Commission and the Advisory Council on Historic Preservation that operation of BVPS-1 would have no effect on significant historic or archaeological sites (Ref. 2.10-5). The same conclusion was drawn in the FES for BVPS-2 (Ref. 2.1-17). PBHP's conclusion from its license renewal environmental review for BVPS indicates that there are no National Register-eligible or -listed archeological or historic properties located in areas potentially affected by BVPS license renewal (Attachment B, Items B.12 through B.15).

In December 2006, the PBHP was formally contacted to acquire an environmental permit for the construction of the sewage conveyance system from BVPS to the borough of Shippingport. A qualified consulting firm was retained to perform the Phase 1a review required for the project, and the results indicated that for that project, no impacts to historic or cultural resources were expected. The PBHP concurred via letter. Is should be noted that permitting actions taken by the PADEP (i.e., the "Part 2" Permit for the conveyance system) required historical and cultural considerations.

In December 2006, FENOC, via letter, again contacted the Pennsylvania, West Virginia, and Ohio agencies responsible for archaeological, historic, and cultural preservation. The communication again described the reason for contact (license renewal) and included solicitation of concerns that the agencies may have, new and significant information since last contact, and an offer to meet with the agency. Since that time, the West Virginia Division of Culture and History (WVDCH) requested more information regarding the cooling towers and transmission lines through Hancock County. After those questions were answered, the WVDCH sent a letter stating that no impacts were expected from the project, and no further consultations were required.

BVPS is working to ensure adequate consideration of potential historic and cultural resources from future activities. For instance, a Phase 1a evaluation and report is being conducted prior to groundwater monitoring well drilling. In addition, BVPS is developing procedures, in consultation with trained and certified personnel, to ensure that future projects and appropriate activities consider potential historic and cultural resources in accordance with the PBHP processes.

TABLE 2.10-1

HISTORIC ATTRACTIONS WITHIN THE 6-MILE RADIUS OF BEAVER VALLEY POWER STATION

Historic Site	Location	Reporting Agency
Beginning Point in the U.S. Public Land Survey	PA/OH border	NPS
David Littell House	Hanover Township, PA	NPS, PBHP
J. R. Mitrovich Property	Midland, PA	PBHP
Lockkeepers' House	Industry, PA	PBHP
USACE Merrill Lock No. 6	Industry, PA	NPS
Midland Carnegie Library	Midland, PA	PBHP
Midland High School	Midland, PA	PBHP
Shippingport Atomic Power Station	Shippingport Borough, PA	PBHP

NPS = National Park Service
PBHP = Pennsylvania Bureau of Historic Preservation
USACE = U.S. Army Corps of Engineers
Ref 2.10-3 (U.S. Department of Interior)
Ref 2.10-4 (Pennsylvania Historical and Museum Commission)

2.11 KNOWN OR REASONABLY FORESEEABLE PROJECTS IN THE BEAVER VALLEY POWER STATION VICINITY

This section briefly describes activities in the area that could have cumulative impacts with the proposed action, which is to operate BVPS Units 1 and 2 for an additional 20 years.

2.11.1 EPA-Permitted Discharges to Air, Water, and Soil

In its "Envirofacts Warehouse" online database, the EPA identifies dischargers to air, water, and soil. BVPS is located in a heavily industrialized area of the Ohio River Valley. A search of the three counties that are within 6 miles of BVPS is summarized below.

A search on Beaver County, Pennsylvania, determined that 96 industries produce and release air pollutants, 57 facilities have reported toxic releases, 378 facilities have reported hazardous waste activities, 9 potential hazardous waste sites are part of the Superfund program, and 183 facilities are permitted to discharge to the waters of the United States. (Ref. 2.11-1)

A search on Columbiana County, Ohio, determined that 52 industries produce and release air pollutants, 31 facilities have reported toxic releases, 266 facilities have reported hazardous waste activities, 3 potential hazardous waste sites are part of the Superfund program, and 64 facilities are permitted to discharge to the waters of the United States. (Ref. 2.11-1)

A search on Hancock County, West Virginia, determined that 18 industries produce and release air pollutants, 13 facilities have reported toxic releases, 120 facilities have reported hazardous waste activities, 8 potential hazardous waste sites are part of the Superfund program, and 37 facilities are permitted to discharge to the waters of the United States. (Ref. 2.11-1)

2.11.2 Federal Facilities Near Beaver Valley Power Station

USACE operates a series of locks and dams on the Monongahela, Allegheny and Ohio Rivers. Eight of these locks and dams are located on the lower Allegheny River, nine control waters on the lower Monongahela, and six are operated on the upper Ohio River. The Montgomery Lock is located approximately 3 miles upriver and is the closer to BVPS than the New Cumberland Lock (Jefferson County, Ohio). There are approximately 550 commercial lockages through each of these locks every month.

The USACE and FWS are in the planning stages of projects that could influence habitat and associated aquatic and riparian communities in the upper Ohio River. These projects include the Ohio River Navigation Study, the Ohio River Ecosystem Restoration Program, continuation of commercial dredging, and refuge acquisitions. Specific activities associated with most of these projects are not yet well defined. However, because the nature of these programs is restoration and maintenance, which under the mission and control of USACE would result in small impacts, there is little potential that any actions presently contemplated would result in cumulative impacts with extended operation of BVPS.

There are no significant military facilities within a 50-mile radius of the plant site.

The Federal Bureau of Prisons (FBOP) operates a low-security facility for male prisoners 3 miles east of Lisbon, Ohio. The FBOP also runs a minimum-security camp for male prisoners adjacent to the main prison. Combined, these two facilities currently house approximately 2,500 inmates. (Ref. 2.11-3)

2.11.3 Industries Near Beaver Valley Power Station

Industrial land occupies 5,073 acres of land in Beaver County. This includes 6 industrial/business parks that are located on a total of approximately 314 acres. Beaver County is home to a diversity of large industries, with a strong foundation in steel and chemical manufacturing. Notable industrial facilities near BVPS, in Beaver County, include the BASF Chemical plant, the Nova Chemical Plant, the Buckeye Pipeline Company, Marathon Ashland Petroleum, and a Jones and the Laughlin Steel Corporation steel mill. Horsehead Corporation zinc recycling plant is located in Monaca and has the distinction of being one of the largest employers in Beaver County (Ref. 2.1-9, 2.1-3).

Downstream of the site, the towns of East Liverpool, Ohio, and Newell, Pennsylvania, are centers for the manufacture of ceramics and pottery. The Homer Laughlin China Company of Newell, Pennsylvania, employs approximately 1,100 workers and is one of the largest industries downstream of the site (Ref. 2.1-10).

DCP Midstream Partners, a subsidiary of Duke Energy Field Services, recently installed a twenty-four tank storage and pumping facility at its Midland Terminal. The Midland Terminal is located across the Ohio River from BVPS in Industry, Pennsylvania, and is one of the largest aboveground, non-refrigerated tank farms in the nation with over 2 million gallons of storage capacity. (Ref. 2.11-4)

2.11.4 Energy Utilities Near Beaver Valley Power Station

There are three coal fired power plants in close proximity to the BVPS. AES Beaver Valley Cogeneration and G.F. Weaton power plants are located in the town of Monaca, Pennsylvania (Ref. 2.11-5). AES Beaver Valley produces 138.5 megawatts (MW) of electricity and the G.F. Weaton plant produces 120 MW (Ref. 2.11-6). FirstEnergy's Bruce Mansfield Power Plant is located in Shippingport, Pennsylvania, on the Ohio River. Its three coal-fired units produce 2,505 MW of electricity (Ref. 2.1-8). Beaver County also has two small hydroelectric facilities, Townsend Hydro (5.2 MW) and Beaver Valley Patterson Dam (1.2 MW) (Ref. 2.11-5; Ref. 2.11-6).

FirstEnergy's W.H. Sammis Power Plant is located approximately 21 river miles downstream of BVPS. This large power plant features seven coal-fired units and five oil-fired peaking units with a combined capacity of 2,316 MW.

2.12 REFERENCES

Note to reader: This list of references identifies web pages and associated URLs where reference data was obtained. Some of these web pages may likely no longer be available or their URL addresses may have changed. FENOC has maintained hard copies of the information and data obtained from the referenced web pages.

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3.0 THE PROPOSED ACTION

NRC

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

FENOC requests that the NRC renew the operating licenses for the BVPS Units 1 and 2 for the maximum period currently allowable under the *Atomic Energy Act* and the NRC's regulations at 10 CFR 54.31. The action being sought would preserve the option to operate BVPS-1 and BVPS-2 for an additional 20 years beyond the current operating license terms. Renewal would thereby enable the Commonwealth of Pennsylvania, FirstEnergy Corporation and its subsidiary companies, and other participants in the wholesale power market to rely on BVPS to meet future needs for electric power through the period of extended operation of these generating units.

FENOC presents in the following sections of Chapter 3 a description of BVPS facilities and activities relevant to assessments presented in Chapter 4 of this ER. Section 3.1 provides a general description of selected plant design and operating features. Sections 3.2 through 3.4 address activities necessary to support the renewed BVPS-1 and BVPS-2 operating licenses.

3.1 GENERAL PLANT INFORMATION

General information about the design and operational features of the BVPS site of interest from an environmental impact standpoint is available from a number of documents. Among the most comprehensive sources are the FESs prepared by the NRC or its predecessor agency, the U.S. Atomic Energy Commission (AEC), and Updated Final Safety Analysis Reports (UFSARs). In 1973, the AEC issued FESs that addressed construction and operation of BVPS-1 (Ref. 3.1-1) and BVPS-2 (Ref. 3.1-2). In 1985, the NRC issued an additional FES that addressed operation of BVPS-2 (Ref. 3.1-3). FENOC routinely updates the UFSARs for BVPS-1 and BVPS-2 (Ref. 3.1-4; Ref. 3.1-5) to reflect current plant design and operating features. FENOC relied on these documents, operating manuals, design-basis documents, technical documentation related to power uprates of the units, license renewal application documents, and other relevant sources of information as a basis for descriptions of BVPS presented in the remainder of Section 3.1.

3.1.1 Major Facilities

Developed or maintained portions of the 453-acre BVPS site occupy approximately 230 acres, primarily on alluvial gravel terraces bordering the New Cumberland Pool of the Ohio River. As shown on Figure 2.1-3, the main BVPS site complex, including the power block, ancillary facilities, and switchyard, is located riverward (north) of SR 168 and downstream from the southern approach to the Shippingport Bridge. Some support facilities, including the emergency response facility (ERF), training and simulator buildings, site engineering building, and warehouses, are located immediately upstream from the approach to the bridge. Extensive parking areas are located on site for normal operations staff and contractor employees (e.g., for outages). The BVPS Meteorological Tower and the General Distribution Center are on FENOC property adjacent to the BVPS site.

Power block facilities for BVPS-1 and BVPS-2 are arranged in an approximate mirror image and are located within the site protected area (see Figure 2.1-3). Among the major buildings associated with each of the BVPS units in the power block are

- A containment building that houses the nuclear steam supply system including the reactor, steam generators, reactor coolant pumps, and related equipment;
- A fuel and decontamination building, where the spent fuel pool and new fuel storage facilities are located;
- A primary auxiliary building that houses major components of the primary component cooling water system, boric acid storage tanks and pumps, and other safety-related equipment;
- A service building that houses various safety-related equipment;
- A turbine building, where the turbine generator, main condenser, turbine plant heat exchangers, and related equipment are housed; and
- A diesel generator building that houses the emergency diesel generators.

Structures and facilities of interest to this ER and located outside of the power block area in the main plant complex include the BVPS switchyard, located south of the power block, and a cooling tower for each of the BVPS units (see Figure 2.1-3). The two cooling towers are natural-draft, hyperbolic, reinforced concrete shells, approximately 500 feet high. They are the most visually prominent structures on the site and, together with three similar cooling towers and two exhaust stacks from the neighboring Bruce Mansfield Plant, are readily visible for several miles from the communities of Shippingport and Midland and other vantage points within the river valley and on neighboring hills.

Facilities located along the Ohio River shoreline include the alternate intake structure located upstream from the Shippingport Bridge, the BVPS barge slip and boat ramp just upstream from the BVPS-1 cooling tower, the intake structure near the power block, and, downgradient from the former SAPS site, the discharge structure and the Unit 2 emergency outfall system structures (see Figure 2.1-3).

3.1.2 Nuclear Steam Supply, Containment, and Power Conversion Systems

The nuclear steam supply systems for BVPS-1 and BVPS-2 each consist of a pressurized water reactor, reactor coolant system (RCS), and associated auxiliary systems. The RCS is comprised of three closed loops in which reactor coolant is circulated; each loop includes a reactor coolant pump and a steam generator. The reactor coolant, demineralized water to which chemicals are added to control corrosion and moderate the nuclear reaction, circulates under high pressure through the reactor and the tube side of the three steam generators in these closed loops. This portion of the RCS is called the primary system. Heat from the reactor is transferred to conditioned demineralized water in the shell side of the steam generators to produce high-pressure saturated steam that is routed through the steam turbines, condensed back to water in the main condensers, and pumped back to the steam generators, thus comprising an isolated secondary cooling loop. Heat transfer from the main condensers is accomplished by a third cooling loop, the circulating water system, which is discussed further in Section 3.1.3.

The BVPS-1 and BVPS-2 reactors are each licensed for uranium dioxide fuel having a maximum enrichment of 5.0 percent by weight uranium-235 (Ref. 3.1-6 and Ref. 3.1-7, Technical Specifications Section 5.3.1). The fuel, in the form of fuel pellets, is enclosed in fuel rods that are fabricated into fuel assemblies. Each fuel assembly consists of a 17 by 17 array of fuel rods with end fittings and grids to support and limit motion of the fuel rods. There are 157 of these fuel assemblies in the core of each reactor, which also contains neutron absorber rods to control the nuclear reaction. FENOC currently replaces approximately one-third of the fuel assemblies in the reactor cores at intervals of approximately 18 months. The maximum licensed fuel rod burnup for the Westinghouse fuel used in the reactors is currently 62,000 megawatt-days per metric ton of uranium (MWD/MTU) (Ref. 3.1-8, Section 6.2.3).

Spent fuel from BVPS-1 and BVPS-2 is transferred from the reactors and stored in the respective spent-fuel-storage pools. The containment buildings for BVPS-1 and BVPS-2 provide protective enclosures for the respective reactors and associated RCSs and are designed to prevent the uncontrolled releases of radioactive materials into the environment in the unlikely event these systems fail. Major structural features and dimensions of the BVPS-1 and BVPS-2 containment buildings are essentially identical. Each is a heavily reinforced concrete, steel-lined vessel with a flat 10-foot-thick base mat, 4.5-foot-thick cylindrical walls, and a 2.5-foot-thick hemispherical dome. The inside of each containment cylinder is 126 feet in diameter, and the distance from the top of the base mat to the inside of the dome crown is approximately 185 feet. The structures are designed to withstand an internal pressure of 45 pounds per square inch gage (psig), sufficient to withstand design-basis accidents involving failure of the nuclear steam supply system and such external hazards as the probable maximum flood, corresponding to a river surface elevation of approximately 730 feet above NGVD; severe earthquakes; and tornados and associated tornado-generated missiles (Ref. 3.1-4, Section 5.2; Ref. 3.1-5, Section 3.8.1).

BVPS-1 and BVPS-2 achieved commercial operation in October 1976 and November 1987, respectively, and were each initially licensed to operate at a maximum steady-state core power level of 2,652 megawatts-thermal (MWt). However, the operating licenses were subsequently amended by the NRC on September 24, 2001, to permit operation at the maximum power level of 2,689 MWt for each of the two reactors on the basis of new, more accurate instrumentation to measure feedwater flows (Ref. 3.1-9; Ref. 3.1-10). In July 2006, the NRC amended the operating licenses of BVPS-1 and BVPS-2 to increase the maximum power level for both units to 2,900 MWt beginning in years 2007 (Unit 1) and 2008 (Unit 2) (Ref. 3.1-23; Ref. 3.2-1). FENOC intends to operate Unit 1 at the higher power level no later than the completion of the fall 2007 refueling outage, and Unit 2 at the higher power level no later than the spring 2008 refueling (Ref. 3.1-23). Therefore, the description of plant facilities and operations and associated impact evaluations in this ER assume operation of both units at 2,900 MWt.

3.1.3 Cooling and Auxiliary Water Systems

3.1.3.1 Water Use Overview

Water used for BVPS site operations consists of raw water from the Ohio River and potable water from the Midland Borough Municipal Water Authority. Water withdrawn from the Ohio River is used primarily for cooling, initially as once-through, non-contact cooling water for primary and secondary heat exchangers in BVPS-1 and BVPS-2. Most of this water is then used as makeup to the circulating water systems, which provide cooling for the main condensers as described in Section 3.1.2; to replace water lost from evaporation and drift from the cooling towers; and to maintain dissolved solids at design equilibrium. A small fraction of water withdrawn from the river is used as feedwater for production of demineralized water (e.g., for use in nuclear steam supply system primary and secondary cooling loops) and other purposes. Cooling water not consumed by evaporation and drift losses and other treated wastewater streams is ultimately discharged back to the Ohio River in accordance with the National Pollutant Discharge Elimination System (NPDES) permit for the BVPS site issued by the PADEP.

Municipal water from Midland Borough supplies the station domestic water distribution system. Though the BVPS site originally drew water from onsite wells and the Ohio River as supply sources for domestic water, no groundwater is currently used at BVPS. No future use of groundwater is anticipated except for monitoring in accordance with the FENOC Groundwater Protection Program.

3.1.3.2 River Water/Service Water Systems

The BVPS river water/service water systems remain generally as described in the FESs for the units (Ref. 3.1-1, Section 3.4; Ref. 3.1-3, Section 4.2.4), with some minor differences as a result of power uprate and other modifications to site facilities and operations. Under normal operating conditions, cooling water for BVPS-1 and BVPS-2 is obtained from the Ohio River at the intake structure, a reinforced-concrete building located on the riverbank downstream from the BVPS-1 cooling tower and adjacent to the central plant complex at approximate river mile 34.8 (see Figure 2.1-3). Water enters the structure via four intake bays oriented parallel to the riverbank. The entrance to each bay consists of a 15-foot-wide by 13.5-foot-high opening to the river, extending from the floor of the bay at elevation 646.0 feet NGVD to elevation 659.5 feet NGVD, 5 feet below normal pool elevation to prevent entry by floating objects. In each intake bay, water passes through trash racks constructed of steeply sloped steel bars spaced horizontally at 3.5-inch intervals to prevent entry of coarse debris, then through vertical 0.375-inch mesh traveling screens (50 percent open space) for removal of finer debris. Average approach velocity to the screens at normal pool elevation is approximately 0.3 feet per second. Debris accumulated on the trash racks is removed with trash bar rakes and transferred to a trash car; debris accumulated on the traveling screens is removed by rotating and backwashing the screens as needed (automatic or manual operation) and sluicing the debris to a collection basket. Accumulated debris is transported to an approved disposal site.

The operating floor of the intake structure is at the design flood elevation of 705 feet NGVD, 10 feet above the 100-year flood elevation of 695 feet NGVD (Ref. 3.1-12). However, the cooling water pumps in the intake structure are enclosed in cubicles with waterproof flood doors that provide flood protection up to the probable maximum flood elevation of 730 feet NGVD, and the pump intakes are below the low river level at elevation 640 feet, 7 inches NGVD (Ref. 3.1-4, Sections 9.9, 2.7). The minimum river elevation for normal plant operations is 654 feet NGVD (Ref. 3.1-6 and Ref. 3.1-7, Technical Specifications, Section 3.7.5.1).

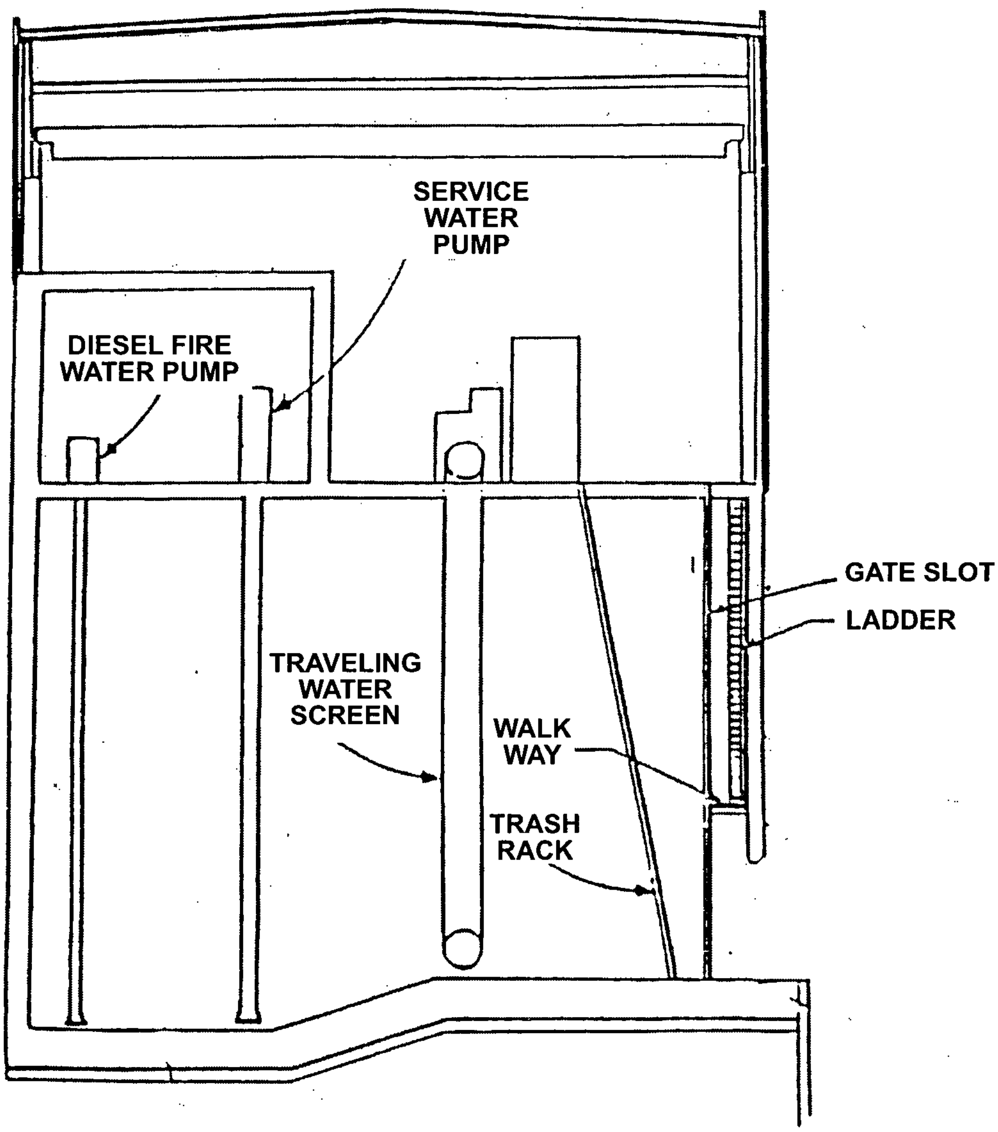
To accommodate the unlikely event that the intake structure is rendered inoperable, an alternate intake structure was constructed upstream from the intake structure and the Shippingport Bridge. This facility, smaller than the intake structure but with similar general design features, is normally operated for periodic testing and maintenance only. The auxiliary river water system, of which the alternate intake structure is an essential part, is designed to provide sufficient cooling water for safe shutdown and subsequent cooldown of the RCSs after postulated loss of the intake structure (Ref. 3.1-4, Section 9.16; Ref. 3.1-3, Section 4.2.4).

Water passes through the intake bays of the intake structure to four suction bays housing pumps for individual systems comprised by the BVPS river water/service water systems, primarily composed of the BVPS-1 raw water system (or turbine plant river water system), the BVPS-1 river water system (or reactor plant river water system), and the BVPS-2 service water system. A diagram of the intake structure is provided in Figure 3.1-1. These systems supply once-through cooling water to turbine plant component heat exchangers, reactor plant component heat exchangers, and other plant equipment. During normal operation, one 9,000-gpm river water pump, one 16,000-gpm raw water pump, and two 15,000-gpm service water pumps are running. During periods of high river water temperatures, generally in the July – October period, a second 9,000-gpm river water pump is used (Ref. 3.1-11, Section 4.3.1; Ref. 3.1-13; Ref. 3.1-5, Section 9.2.1.1).

Once cooling water from the BVPS-1 systems has served its plant components, it is discharged to the BVPS-1 circulating water system to make up operational water losses from that system. Similarly, once cooling water from the BVPS-2 service water system has served its plant components, most of it is discharged to the BVPS-2 circulating water system downstream from the main condenser to replace operational losses from that system. As much as 8,400 gpm (19 cfs), originating from the BVPS-2 primary (reactor plant) heat exchangers and components, are discharged to the Ohio River via the emergency outfall structure to reduce silt accumulation in that system (Ref 3.1-1, Section 3.4; Ref. 3.1-3, Section 5.3.2.1; Ref. 3.1-11, Section 3.7.1). Under normal plant operations, the temperature of this discharge to the emergency outfall structure is approximately 12°F above ambient river temperature (Ref. 3.1-14, Section 5.1.2). As indicated in its "Extended Power Uprate License Amendment Request," FENOC determined that the calculated effect did not invalidate the previous conclusions in the Operating License Stage FES, regarding temperature effects on the Ohio River.

FIGURE 3.1-1

BVPS INTAKE STRUCTURE



The Unit 2 emergency outfall system is designed to ensure an unrestricted discharge path for the service water system for both normal operations and accident conditions. It consists of two structures: the overflow structure and the impact basin. Service water is initially routed to the overflow structure, located at approximate elevation 730 feet NGVD at the west end of the former SAPS site. The service water then flows by gravity through interconnected piping to the impact basin, which is located approximately 12 feet above normal pool elevation at river mile 34.9 (Ref. 3.1-3, Section 4.2.4). The overflow structure provides missile protection for the ends of the two discharge pipes; the impact basin prevents riverbank erosion.

3.1.3.3 Circulating Water Systems

The BVPS-1 and BVPS-2 circulating water systems are both closed-loop cooling systems that use a natural-draft, hyperbolic cooling tower for removal of waste heat from the main condensers of their respective units. In these systems, water heated by passage through the main condensers is circulated through the cooling towers where waste heat is removed primarily by evaporation. The cooled water, which accumulates in a basin beneath each tower, is recirculated back through the main condensers.

Water directly evaporated from the cooling towers and that which escapes the towers as mist (drift) represents consumptive loss from the Ohio River due to BVPS-1 and BVPS-2 operation. Power uprate of the BVPS units would increase the circulating water temperatures and evaporation rates from the cooling towers. FENOC estimates that operation of the units at the fully uprated power level of 2,900 MWt would increase evaporation rates from each tower by approximately 10 percent from pre-uprate conditions. Drift losses, approximately 250 gpm and 65 gpm for BVPS-1 and BVPS-2, respectively (collectively 0.7 cfs), which are dependent only on circulating water flow rates, would not be changed by the power uprates (Ref. 3.1-11, Sections 3.7 and 15.2).

FENOC applied the estimated 10 percent increase in evaporative losses resulting from the power uprates to the highest average and highest maximum estimates for the BVPS units as reported in the BVPS-1 and BVPS-2 FESs (Ref. 3.1-1, Sections 3.3, 3.4; Ref. 3.1-3, Section 4.2.3), BVPS-1 and BVPS-2 operating license stage ERs (Ref 3.1-14, Tables 3.3-1, 3.3-3, and 3.3-4; Ref. 3.1-15, Section 3.1.4), and NPDES permit support documentation (Ref. 3.1-16) to derive consumptive loss estimates for the uprated units. On this basis, annual average and maximum monthly average consumptive losses from the Ohio River from BVPS site operations, which conservatively assume simultaneous operation of both units at a maximum licensed power level of 2,900 MWt, would be approximately 18,000 gpm (40 cfs; 29,000 acre-feet/year) and 20,400 gpm (45 cfs; 33,000 acre-feet/year), respectively. Based on local meteorology, maximum expected consumption rates occur in July and August (Ref. 3.1-3, Section 4.2.3.1).

As previously noted, water from the BVPS-1 river water system is discharged to the BVPS-1 circulating water system, and water from the BVPS-2 service water system (excluding up to 8,400 gpm [19 cfs] discharged to the emergency outfall structure) is discharged to the BVPS-2 circulating water system. This makeup water replaces consumptive losses due to evaporation and drift from the cooling towers. Makeup to the circulating water systems is always greater than the consumptive losses. The excess makeup overflows a weir at the cooling tower basin and is directed back to the river as cooling tower blowdown. Cooling tower blowdown flow also keeps dissolved solids in the circulating water systems within design limits. Makeup flows to the circulating water systems would be essentially unchanged from pre-uprate conditions. Less water would overflow the basin as cooling tower blowdown when operating the uprated units because the consumptive loss would increase (due to increased evaporation).

These modified operating conditions would change the flow volume and physical-chemical characteristics of the cooling tower blowdown. FENOC estimates that, relative to pre-uprate conditions, operation of the uprated units at full power would increase the maximum dissolved solids concentration of the blowdown by approximately 7 percent, increase blowdown temperature by a maximum of 2.9°F at design conditions noted above, and decrease blowdown flow in amounts approximately equivalent to the increase in evaporation rates (Ref. 3.1-11, Section 3.7). FENOC's review of the source documentation for consumptive losses cited above (Ref. 3.1-1, Sections 3.3, 3.4; Ref. 3.1-3, Section 4.2.3.1; Ref. 3.1-14, Tables 3.3-1 and 3.3-3; Ref. 3.1-15, Section 3.1.1; and Ref. 3.1-16) indicates that the highest estimate of maximum monthly average blowdown flow for both BVPS units combined at current maximum authorized power levels is approximately 42,500 gpm (95 cfs). BVPS operational monitoring data indicate that this is likely a conservative upper-bound estimate; for a recent 2-year period prior to power uprate (2001 – 2002), actual maximum monthly average blowdown discharge flow from BVPS was approximately 38,000 gpm (85 cfs). On this basis, FENOC concludes that the combined maximum monthly average blowdown flows for the BVPS units operating at the uprated maximum power levels of 2,900 MWt would be less than 42,500 gpm (95 cfs).

Predicted monthly average temperature differences between the blowdown and the ambient river water at current authorized maximum power levels range from 2.4°F in August to 28.6°F in January. During June through August, when ambient river temperatures under this prediction are highest (75 – 80°F), this temperature differential ranges as high as 7.2°F (Ref. 3.1-3, Section 4.2.4; Ref. 3.1-14, Table 5.1-6). BVPS operational monitoring indicates that this range is appropriate for periods of high ambient water temperature. For example, average temperature differential between BVPS blowdown and the ambient river was approximately 5.5°F for August 2002, a month in which both BVPS units were operated at or near full power and ambient temperature of the Ohio River averaged 82°F, at or near its highest of the year (Ref. 3.1-17). Considering the expected maximum increase of 2.9°F in blowdown temperature at design conditions noted above, FENOC expects that this monthly average temperature differential during summer months when ambient river temperatures are highest (e.g., June-August) would range from approximately 5°F to 10°F when both units are operating at maximum power levels of 2,900 MWt. The predicted and actual temperature differentials and ambient river readings are summarized in Table 3.1-1.

FENOC discharges all cooling tower blowdown to a common outfall, the BVPS discharge structure, when river temperatures are cooler, generally in the period November through June. When river temperatures are warmer and the second BVPS-1 river water pump is running, generally during the period July – October, FENOC discharges as much as approximately one-third of the BVPS-1 blowdown flow to a separate Ohio River outfall, the BVPS-1 emergency cooling tower overflow.

TABLE 3.1-1

WATER TEMPERATURE AT MAXIMUM POWER LEVELS

Timeframe	Temperature Differential (BVPS blowdown and ambient river)	Ohio River average ambient temperature (°F)	Reading
August to January	2.4°F to 28.6°F	-----	Predicted
June to August	7.2°F	75-80°F	Predicted
August 2002	5.5°F	82°F	Actual

The BVPS blowdown discharge structure is a concrete and sheet piling structure located at the Ohio River shoreline, approximately 100 feet upstream from the emergency outfall impact basin. The structure directs the discharge over an energy-absorbing weir and to the river through a 55 foot-long channel angled downstream (Ref. 3.1-3, Figures 4.6 and 4.9). The BVPS-1 emergency cooling tower overflow is a simple submerged-pipe outfall at a headwall on the Ohio River shoreline a short distance upstream from the intake structure.

3.1.3.4 Biofouling Control

The BVPS river water/service water systems and circulating water systems are vulnerable to fouling from microbiological organisms and two notable macrofouling organisms that occur in the Ohio River at the site, the asiatic clam (*Corbicula fluminea*) and zebra mussel (*Dreissena polymorpha*). FENOC uses approved biocides in these systems to control biofouling in accordance with all use and discharge requirements, including provisions of the NPDES permit issued to the BVPS site (Ref. 3.1-18). FENOC currently uses hypochlorite, bromide, and a quaternary amine formulation for biofouling control, which can be applied at the intake structure and in the circulating water systems upstream from the main condensers. BVPS uses procedures to control application, perform monitoring, and comply with NPDES permit limits for discharge of these biocides and associated residuals. In addition, FENOC adds bentonite clay to the cooling water prior to discharge as needed to ensure that free quaternary amine formulation concentrations are below detectable levels, as specified in the NPDES permit to protect riverine aquatic life.

3.1.3.5 Thermal Discharge Characteristics

As noted above in Sections 3.1.3.2 and 3.1.3.3, cooling water discharges from the uprated BVPS units to the Ohio River in the summer months would include up to approximately 19 cfs of once-through cooling water at a temperature of up to 13°F above ambient river temperature via the emergency outfall structure and a maximum of approximately 95 cfs of cooling tower blowdown at temperatures of 5°F –10°F above the ambient river temperature (as a monthly average), primarily at the outfall structure. Analyses conducted in connection with construction of BVPS-2 (Ref. 3.1-2, Section 5.2; Ref. 3.1-14, Section 5.1.2) indicate that the resulting thermal plume is very small. For summer conditions, these analyses assumed extreme low flow conditions (e.g., river flow of 5,000 cfs) and warm ambient river temperatures (84°F in one of two modeling studies reported) and included the comparatively large thermal discharge from the former SAPS unit (assumed to be 254 cfs at 14.5°F – 14.9°F above ambient river temperature in the modeling studies). The BVPS cooling water discharge assumed in the studies ranged from 37 cfs at 6°F above ambient to 72 cfs at 10.4°F above ambient. Results for these extreme summer conditions showed that the discharge from the BVPS site combined with that from the former SAPS unit would result in a thermal plume in which the 5°F isotherm encompassed less than or equal to 2 acres, extended downstream 500 – 1,000 feet, and was largely confined to the upper few feet of the river. Considering the much lower cooling water flow and temperature expected from operation of the BVPS units at their uprated maximum authorized power levels at these summer conditions, FENOC estimates that the resulting plume from each discharge, as represented by the 5°F isotherm, would be much smaller than 2 acres and would extend downriver much less than 500 – 1,000 feet.

3.1.3.6 Municipal Water Supply and Sanitary Wastewater Treatment

The BVPS site uses an average of approximately 1.32 million gallons per month (44,000 gpd or 0.044 mgd) of filtered, chlorinated water from the Midland Borough Municipal Water Authority for the station domestic water system (Ref. 3.1-19). This system distributes water throughout the BVPS site for potable, sanitary, emergency showers, eyewash stations, and miscellaneous other uses (Ref. 3.1-20).

Most of the BVPS site domestic water is routed as sanitary wastewater with approximately 70 percent being conveyed to the Shippingport Municipal Wastewater Plant, and the remaining balance to the BVPS-sewage treatment plant for treatment by aerobic digestion (Ref. 3.1-3, Section 4.2.6). The Unit 1 treatment plant includes tanks and basins for flow equalization, a rotating biological contactor, clarifier/skimmer, a chlorine contact tank, and a sludge storage/digestion tank. Wastewater is treated, disinfected by chlorination, and discharged with limits prescribed in the site NPDES permit (Ref. 3.1-18). Monthly average discharge from the BVPS-1 sewage treatment plant is limited by permit to 0.023 mgd. Effluent from the BVPS-1 sewage treatment plant is discharged via NPDES Permit Outfall 203 to a combined process/stormwater sewer to the Ohio River at final Outfall 003

FENOC entered into an agreement with the borough of Shippingport to jointly develop the new sewage treatment plant located upstream along the Ohio River between the BVPS site and the Bruce Mansfield Plant. The municipal plant began operation in April 2006. FENOC tied into the new treatment plant and retired the BVPS Unit 2 sewage treatment plant on May 1, 2007. The Unit 1 plant retirement and final tie-in occurred on May 23, 2007.

3.1.4 Power Transmission Systems

Power output from the BVPS-1 and BVPS-2 main generators is fed to the transmission grid at the BVPS switchyard (Beaver Valley Substation), situated on the southern perimeter of the power block area on the BVPS site (see Figure 2.1-3). Established as an expansion of the switchyard for the former SAPS site, the substation was required for interconnections between Duquesne Light and other member companies of a then-active power coordinating group, the Central Area Power Coordinating Group (CAPCO), and was placed in service for that purpose in 1972 prior to completion of BVPS-1. The requirement for interconnections at this location, which enabled a direct feed to the transmission system, was one of the reasons for establishing

BVPS-1 at this location (Ref. 3.1-1, Section 3.8). Ownership of the substation switching facilities is apportioned between American Transmission Systems, Inc. (i.e., ATSI, a FirstEnergy Corporation subsidiary) and Duquesne Light, and both FENOC and Duquesne Light agree that the Beaver Valley Substation remains an essential transmission system interconnection independent of BVPS.

The substation is organized as a 345-kV switchyard on the east side of the substation and a 138-kV switchyard on the west side of the substation, providing connection for a total of 13 transmission lines (circuits), six 345-kV lines and seven 138-kV lines (Ref. 3.1-4, Section 8.3). ATSI owns four of the 345-kV lines; the remaining 345-kV lines and all 138-kV lines from the substation are owned by Duquesne Light. Table 3.1-2 contains a basic description of these lines as currently configured from east to west out of the substation, as determined from review of FENOC and Duquesne Light records.

All of these transmission lines are operated as integral parts of the transmission grid or to service major electric customers from the grid (e.g., Jones & Laughlin Steel) independent of BVPS. Therefore, FENOC and Duquesne Light expect that these lines would remain in service irrespective of continued operation of BVPS-1 and BVPS-2.

The transmission corridors of concern for license renewal are those constructed for the specific purpose of connecting the plant to the transmission system [10 CFR 51.53(c)(3)(ii)(H)]. The NRC further elaborates in the GEIS and guidance that the corridors to be addressed are those between the plant switchyard and their connection with the existing transmission system and those reviewed as part of the construction permit for the plant (Ref. 3.1-21, Section 4.5, page 4-59; Ref. 3.1-22, Section 4.13). FENOC and Duquesne Light consider the Beaver Valley Substation to be the BVPS connection with the transmission system and note that no transmission lines were constructed specifically for BVPS-1 (Ref. 3.1-1, Section 3.8). Further, the only transmission line construction associated with BVPS-2 was Beaver Valley-Crescent Line 318 (345-kV) and minor reconfiguration of existing 345-kV line segments exiting the substation (now parts of the Beaver Valley Hanna line and Beaver Valley Mansfield No. 1 and No. 2 lines), as described in Table 3.1-2 and depicted in Figures 3.1-2 and 3.1-3 (Ref. 3.1-3, Section 4.2.7). Although this construction was not undertaken for purposes of connecting the site to the existing transmission system, FENOC notes that it was done in preparation for BVPS-2 operation to increase power system stability and reduce potential overloads and was addressed by the NRC in the BVPS-2 Operating License Stage FES (Ref. 3.1-3, Section 4.2.7). In consideration of these factors, FENOC has addressed Beaver Valley-Crescent Line 318 and these 345-kV line reconfiguration segments in this license renewal environmental review.

FENOC and Duquesne Light both implement specific programs for ensuring continued safe and reliable operation of their transmission lines, continued compatibility of land uses on the transmission corridors, and environmentally sound maintenance of the corridors. The following paragraphs provide a general description of these programs. The FENOC programs are applicable to reconfiguration segments as depicted in Figure 3.1-2; the Duquesne Light programs are applicable to Beaver Valley-Crescent Line 318, depicted in Figure 3.1-3.

TABLE 3.1-2

TRANSMISSION LINES FROM BEAVER VALLEY SUBSTATION

Beaver Valley-Hanna (345 kV; ATSI Line TZ1896, former Duquesne Light Line 320)
Extends 59.1 miles northwestward (6 miles in Pennsylvania, 53 miles in Ohio) to ATSI's Hanna Substation at Ravenna, Portage County, Ohio. After exiting the Beaver Valley Substation, this line is strung on two dedicated towers, then shares the same towers as ATSI's Chamberlin-Mansfield 345-kV line as it crosses the Ohio River just upstream from the Shippingport Bridge at river mile 34.6 and enroute to the Hanna Substation. The line was originally independent of BVPS-2 and connected to the Mansfield Substation. When BVPS-2 construction was completed in the mid-1980s, 345-kV transmission line connections out of the Beaver Valley Substation were reconfigured to increase power system stability and reduce potential overloads[a.] This reconfiguration formed the current Beaver Valley-Hanna 345-kV line by changing connections to the existing Hanna-Mansfield Line 320 from the Mansfield Substation to the Beaver Valley Substation (see Figure 3.1-2). This action was addressed by the NRC in its environmental review for the initial BVPS-2 operating license application[a,b.] The current alignment of the reconfigured connections into the Beaver Valley Substation differ from those described in the NRC's environmental review only in that one additional tower has been constructed on a developed portion of the BVPS site.
Beaver Valley-Mansfield No. 2 (345 kV; ATSI Line TZ2689-A, former Duquesne Light Line 310)
Extends 1.5 miles northeastward on double-circuit steel lattice towers to the Mansfield Substation at the neighboring Bruce Mansfield Plant. After the initial tower out of the Beaver Valley Substation, the line shares the same towers as a segment of ATSI's Chamberlin-Mansfield 345-kV line. Except for the connection to the Beaver Valley Substation made as part of reconfiguration activities undertaken for system stability when BVPS-2 came on line, as described above (see Figure 3.1-2), this line was previously in service as a segment of Hanna-Mansfield Line 320. As noted above for the Beaver Valley-Hanna line, the NRC addressed this reconfiguration action in its environmental review for the initial BVPS-2 operating license application.[a,b]
Beaver Valley-Mansfield No. 1 (345 kV; ATSI Line TZ2691-A, former Duquesne Light Line 316)
Extends 2.0 miles northeastward on double-circuit steel lattice towers to the Mansfield Substation at the neighboring Bruce Mansfield Plant. After the initial three towers out of the Beaver Valley Substation, the line shares towers with a short segment of Duquesne Light's Mansfield-Crescent Line 315, also energized at 345 kV. This line corresponds to the Duquesne Light portion of a Pennsylvania Power Company interconnection to their Shenango Substation, which was noted by the AEC in the BVPS-1 FES as having been constructed to meet CAPCO commitments, irrespective of BVPS-1 construction.[c] A new connection to the Beaver Valley Substation was made as part of the reconfiguration activities undertaken for system stability when BVPS-2 became operational, as discussed above (see Figure 3.1-2). As with the Beaver Valley-Hanna and Beaver Valley-Mansfield No. 2 lines, the NRC addressed this reconfiguration action in its environmental review for the initial BVPS-2 operating license application.[a,b]
Beaver Valley-Crescent (345 kV; Duquesne Light Line 318)
Extends 15.8 miles southeastward to Duquesne Light's Crescent Substation, Crescent Township, Allegheny County, Pennsylvania (Figure 3.1-3). For the initial 12-mile segment from the Beaver Valley Substation, the line shares double-circuit steel lattice towers with Duquesne Light's Beaver Valley-Clinton Line 314, a 345-kV line described below, on a 150-foot-wide corridor. For the 3.8 mile segment nearest the Crescent Substation, the line shares double-circuit single-pole steel structures with Duquesne Light's Collier-Crescent Line 331, a 345-kV line, on an 85-foot-wide corridor. Approximately 85 percent of the corridor is in right-of-way easements; the remainder is in corporate ownership. Beaver Valley-Crescent Line 318 corresponds to the Beaver Valley-Crescent 345-kV line that the NRC addressed in its environmental review for the current BVPS-2 operating license[a,b.] As described above and depicted in Figure 3.1-2, the NRC noted that this line was constructed to increase power system stability and reduce potential overloads when BVPS-2 became operational.[a,b]

TABLE 3.1-2 (CONTINUED)

TRANSMISSION LINES FROM BEAVER VALLEY SUBSTATION

Beaver Valley-Clinton (345 kV; Duquesne Light Line 314)
Extends 14.6 miles southeastward to the Clinton Substation, Findlay Township, Allegheny County, Pennsylvania (Figure 3.1-3). For the initial 12-mile segment from the Beaver Valley Substation, the line shares towers with Duquesne Light's Beaver Valley-Crescent Line 318; for the 2.6-mile segment nearest the Clinton Substation, the line shares pole structures with Duquesne Light's Collier-Crescent Line 331. This line is a segment of what was described by the AEC in the BVPS-1 FES as the Beaver Valley-Collier 345-kV line. The Beaver Valley-Collier 345-kV line was constructed prior to operation of BVPS-1, to meet CAPCO pool requirements[c]. The Beaver Valley-Collier Line was segmented into the Beaver Valley-Clinton and Clinton-Collier 345-kV lines in 1991, upon construction of a tie-in to the Clinton Substation to facilitate power supply to an expansion of the Pittsburgh International Airport.
Beaver Valley-Sammis (345 kV; ATSI Line TZ-1454-A, former Duquesne Light Line 312)
Extends 13.8 miles (6.1 miles in Pennsylvania, 7.3 miles in West Virginia, and 0.4 mile in Ohio) southwestward, crossing the Ohio River at river mile 54.1 to the Sammis Substation at FENOC's Sammis Power Station, Jefferson County, Ohio. The Beaver Valley-Sammis line was constructed independent of BVPS, and noted as a pre-existing line by the AEC in the BVPS-1 FES.[c]
Beaver Valley-J&L (138 kV; Duquesne Light Line Z-32)
Extends 3.0 miles northeastward on a corridor shared with Beaver Valley-J&L Line Z-33. Spans the Ohio River at river mile 36.5 to the Jones & Laughlin Steel Corp. at Midland, Pennsylvania. The line was constructed to supply Duquesne Light retail load to Crucible Steel (now Jones & Laughlin Steel), irrespective of BVPS.
Beaver Valley-J&L (138 kV; Duquesne Light Line Z-31)
Extends 2.6 miles northeastward on an onsite corridor shared with Beaver Valley-Midland Line Z-30, spans the Ohio River at river mile 35.4, and extends downriver to the Jones & Laughlin Steel Corp. at Midland, Pennsylvania. The line was energized, as BV-Crucible Z-31, to supply Duquesne Light retail load to Crucible Steel (now Jones & Laughlin Steel) from the grid, irrespective of BVPS.
Beaver Valley-Raccoon (138 kV; Duquesne Light Line Z-37)
Extends 7.5 miles eastward to Duquesne Light's Raccoon Substation, Raccoon Township, and Beaver County, Pennsylvania. The line was energized in its present alignment and line designation in 1982 to supply Duquesne Light retail load from the grid. The initial 5.5-mile segment from the Beaver Valley Substation, which shares double-circuit steel lattice towers with Duquesne Light's Beaver Valley-Crescent Line Z-29 138-kV line, represents a redesignation of a segment of the Beaver Valley-Crescent No. 2 138-kV line that was acknowledged by the AEC in the BVPS-1 FES as having been constructed to provide CAPCO company interconnections irrespective of BVPS-1 construction.[c]
Beaver Valley-Crescent (138 kV; Duquesne Light Line Z-29)
Extends 14.8 miles southeastward to Duquesne Light's Crescent Substation, Crescent Township, and Allegheny County, Pennsylvania. The line is a reconfiguration of the Beaver Valley-Crescent 138-kV line noted by the AEC in the BVPS-1 FES as having been developed with a second Beaver Valley-Crescent 138-kV line, collectively called Beaver Valley-Crescent No. 2. The line was built concurrently, but independently, of BVPS-1 to provide interconnections between CAPCO companies. The second 138-kV line comprising the Beaver-Valley-Crescent No. 2 double circuit is now represented by a segment of Beaver Valley-Raccoon Line Z-37 and a realigned segment of Beaver Valley-Crescent Line Z-28.

TABLE 3.1-2 (CONTINUED)

TRANSMISSION LINES FROM BEAVER VALLEY SUBSTATION

Beaver Valley-Crescent (138 kV; Duquesne Light Line Z-28)
Extends 11.4 miles southeastward to Duquesne Light's Crescent Substation, Crescent Township, and Allegheny County, Pennsylvania. Current alignment of this line, which shares double-circuit structures with segments of the Duquesne Light Mansfield-Crescent Line 315 (345 kV) and Beaver Valley-Crescent Line Z-29 (138 kV), was achieved and energized in 1982 in connection with development of Beaver Valley-Raccoon Line Z-37 to supply Duquesne Light retail load. Beaver Valley-Crescent Line Z-28 was originally developed as a second circuit along the original route of Beaver Valley-Crescent Line Z-29, described above. Collectively referred to as Beaver Valley-Crescent No. 2, the original alignments of Lines Z-28 and Z-29 were noted by the AEC in the BVPS-1 construction phase FES as being constructed concurrently but independently of BVPS-1 to provide interconnections between CAPCO companies[c]. Mansfield-Crescent Line 315 represents a reconfiguration of the Beaver Valley-Crescent No. 1 345-kV line noted in the BVPS-1 construction phase FES as planned to be initially energized in 1974 to meet CAPCO pool commitments irrespective of BVPS-1 construction.[c]
Beaver Valley-J&L (138 kV; Duquesne Light Line Z-33)
Extends 3.0 miles northeastward on a corridor shared with Beaver Valley-J&L Line Z-32 and spans the Ohio River at river mile 36.6 to the Jones & Laughlin Steel Corp. at Midland, Pennsylvania. The line corresponds to the Beaver Valley-Crucible 138-kV line indicated by the AEC in the BVPS-1 FES by rerouting approximately 0.5 mile of the then-existing Phillips-Crucible 138-kV line (which serviced the Crucible Steel Company, subsequently purchased by Jones & Laughlin Steel) into the Beaver Valley Substation, independently of BVPS-1[c].
Beaver Valley-Midland (138 kV; Duquesne Light Line Z-30)
Extends 1.6 miles northeastward on an onsite corridor shared with Beaver Valley-Midland Line Z-31 and spans the Ohio River and Phillis Island at river mile 35.3 to the Midland South Substation. This line is the same line noted by the AEC in the BVPS-1 FES as in existence prior to BVPS-1[c]. A tap from this line, routed from the corridor northward to and around the former SAPS site on the BVPS site, was constructed in 1984 to provide 138 kV of offsite power feed to the BVPS-2 system station service transformer.

[a]Ref. 3.1-3, Section 4.2.7
[b]Ref. 3.1-14, Section 3.9
[c]Ref. 3.1-1, Section 3.8
AEC = U.S. Atomic Energy Commission
ATSI = American Transmission Systems, Incorporated
BVPS = Beaver Valley Power Station
CAPCO = Central Area Power Coordinating Group
FES = Final Environmental Statement
kV = kilovolt(s)
NRC = U.S. Nuclear Regulatory Commission

FIGURE 3.1-2

345-KILOVOLT RECONFIGURATIONS FOR BEAVER VALLEY POWER STATION UNIT 2

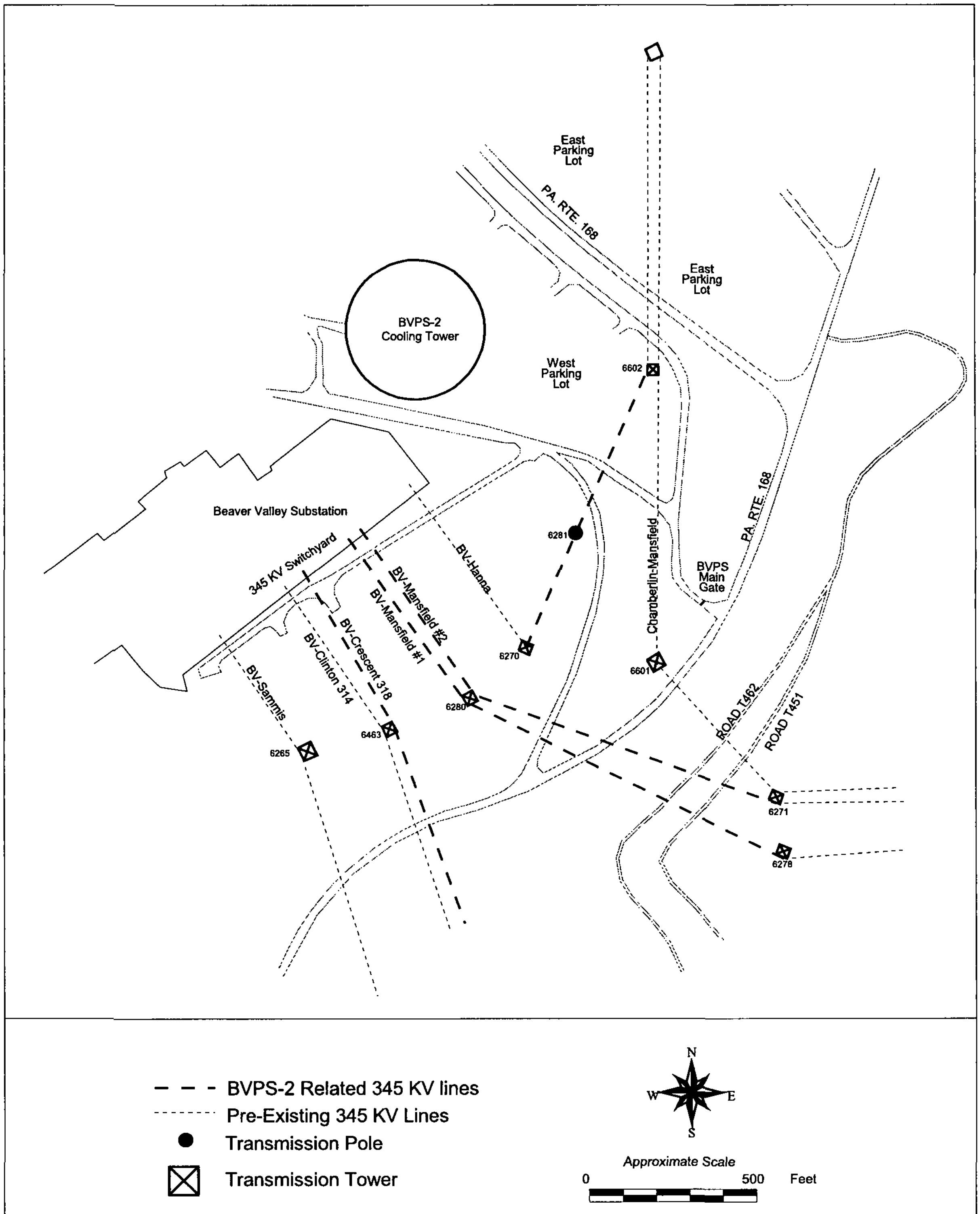
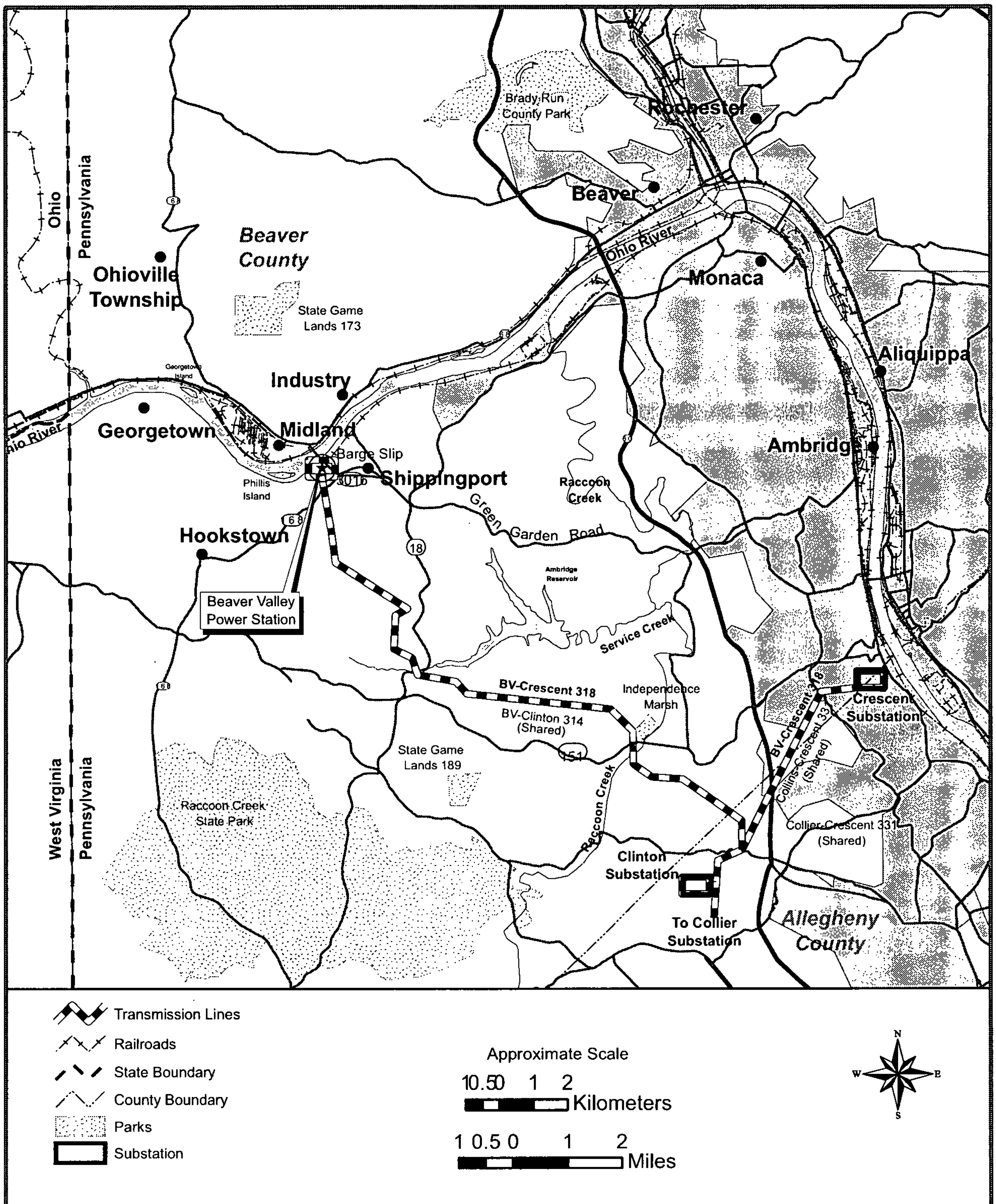


FIGURE 3.1-3

BEAVER VALLEY-CRESCENT LINE 318 CORRIDOR



FENOC performs two and Duquesne Light performs one helicopter inspection of selected line or line segments per year to determine the physical condition of towers, conductors, and other equipment; status of vegetation communities; land-use changes; and any encroachments on the line (e.g., buildings). Similarly, lines or line segments are selected each year, based on past performance and other factors, for on-foot inspection. Written reports are prepared, and conditions needing follow-up are referred for action to appropriate departments, including FENOC's Forestry Services and Right-of-Way Management and Duquesne Light's Vegetation Management Department. In addition, both companies send crews to problem areas to make onsite inspections and repairs, as needed. The Duquesne Light program provides detailed helicopter inspection and visual on-ground inspections every 5 years and 8 – 10 years, respectively, for each of its lines, including Beaver Valley- Crescent Line 318.

FENOC conducts routine vegetation maintenance of its rural transmission line corridors approximately every 5 years. Trees and shrubs that do not interfere with transmission facilities are not disturbed, and portions of corridors that are not cultivated or devoted to other intensive uses are managed to promote a diversity of shrubs, grasses, and other groundcover that provides wildlife food and cover. Maintenance includes removal or pruning of woody vegetation as necessary to ensure adequate line clearance (no less than 30 feet from the conductor for transmission lines operated above 138 kV) and to allow vehicular access for maintenance. Approved herbicides are used on a selective basis to prevent regrowth from trees stumps (for broadleaf species) and to control small trees and other incompatible vegetation; selected trees are treated with tree growth regulators to reduce rate of crown growth and need for pruning. Mowing and broadcast application of herbicides are used in limited circumstances only. It is FENOC's policy not to use herbicides in or adjacent to stream crossings. FENOC may occasionally use herbicides in wetland areas on a case-specific basis; however, only herbicides that are EPA-approved for application in wetlands are used. Herbicide applications are performed by state-licensed applicators in accordance with all applicable federal, state, and local laws and regulations.

Duquesne Light targets maintenance of vegetation on its transmission line corridors on an average interval of 6 years. Maintenance intervals are determined by the effectiveness of management practices and potential for disruption of operating system integrity on individual segments due to site-specific situations. The border-zone, wire-zone technique of vegetation management is used where applicable on the company's predominantly rural transmission corridors. The wire zone, which is the area beneath the conductors and extending horizontally to 10 feet on either side of the outer conductors, is managed to promote a diverse mix of herbaceous plant species that serves as food and bedding for wildlife. In the border zone, the area extending from the wire zone to the large tree edge, establishment of low-growing shrubs and other compatible vegetation is promoted. Low-growing trees and shrubs that do not interfere with transmission facilities are left undisturbed in the border zone, providing food and shelter for wildlife.

Maintenance efforts prescribed for transmission corridors include the removal, pruning, and chemical control of woody vegetation as necessary to ensure adequate clearance for safe and reliable operation of the line. Management of the corridor edge and beyond involves identification and removal of hazardous trees. Along the established large tree edge, typically about 35 feet from the nearest conductor, selective pruning is performed to ensure clearance for edge trees until the next maintenance effort. On the floor of the corridor, all larger brush and smaller trees are controlled up to the natural large tree edge. EPA-approved herbicides are used on a selective basis to prevent regrowth from the stumps of cut trees and brush and to control smaller standing trees and incompatible vegetation. The use of herbicides is promoted for the control of undesirable vegetation rather than mechanical cutting by hand or with mowers. Herbicide applications are performed by state-licensed applicators in accordance with all applicable federal, state, and local laws and regulations.

3.1.5 Waste Management Systems

3.1.5.1 Non-Radioactive Waste System

Nonradioactive waste is produced from plant maintenance, cleaning, and operational processes. The majority of the wastes generated consists of nonhazardous waste oil and oily debris and result from operation and maintenance of oil-filled equipment. Universal wastes, such as spent lamps and batteries common to any industrial facility, comprise a majority of the remaining waste volumes generated. Hazardous wastes routinely make up a small percentage of the total wastes generated and include and consist of spent and off-specification (e.g., shelf-life expired) chemicals, laboratory chemical wastes, Freon-contaminated oil, and occasional project-specific wastes.

Nonradioactive chemicals, paint, oil, lamps, and other items that have either been used or exceeded their useful shelf life are collected in designated collection areas and managed in accordance with federal (40 CFR) and state (25 PA Code) rules via BVPS and FENOC procedures. The materials are received in various forms and are packaged to meet regulatory requirements prior to final disposition at an offsite facility licensed to receive and mange the material. Typical waste streams include waste oil, oily debris, glycol, lighting ballasts containing PCBs, lamps, batteries, and hazardous wastes.

Adopting the hierarchy and practices induced by the *Pollution Prevention Act* of 1990, BVPS has been a "Small Quantity Generator [SQG] of Hazardous Waste" since 1995, with the exception of September 2001 due to steam generator chemical cleaning. The BVPS and FENOC Chemical Control Program provides the pollution-prevention and source-reduction philosophy. BVPS efforts were recognized with a Governor's Award for Environmental Excellence in 1999.

BVPS Categorical Waste Status:

- Hazardous Waste—SQG
- Universal Waste—Small Quantity Handler
- Pennsylvania Residual Waste (non-hazardous waste; essentially all other non-radioactive, non-hazardous wastes)—Large Quantity Generator (LQG)

Chemical and biocide wastes are produced from processes used to control the pH in the coolant, control scale, control corrosion, and clean and defoul the condenser. These waste liquids are typically combined with cooling water discharges in accordance with the BVPS NPDES Permit No. PA0025615. An agreement was made between FirstEnergy Corporation and Shippingport Borough for BVPS to dispose of its sanitary wastes at the municipal facility in 2007. Previously, BVPS operated a sewage treatment plant for each operating unit.

A more detailed compliance discussion and a listing of environmental authorizations are included in Chapter 9.

3.1.5.2 Liquid Radioactive Waste Systems

The liquid radioactive waste system is designed so that effluents released by the system, when mixed with the cooling tower blowdown, meet the requirements of 10CFR20.

The design is based on receiving, segregating, and batch-storing three categories of solutions: high-level wastes, low-level waste, and laundry and contaminated showers. The essence of this system is batch control of all liquids and recovery of primary liquids where feasible. Accommodation of the wide range of volumes and activities which may enter the system is achieved by providing a high degree of flexibility in batch operation.

The liquid radioactive waste treatment system (evaporator and/or demineralizer) is used to reduce the radioactive materials in each liquid waste batch prior to its discharge when the projected doses due to liquid effluent releases (when averaged over 31 days) would exceed 0.06 mrem to the total body or 0.2 mrem to any organ.

The system can accommodate the full range of volumes and activities delivered to it. Suitability for discharge is determined not only by comparison of waste samples with applicable limits, but also by the opportunity afforded the station to further reduce activity with existing equipment.

3.1.5.3 Gaseous Radioactive Waste System

The gaseous radioactive waste disposal system is designed to process effluents to meet the requirements of 10CFR20. The system provides selective holdup such that the short-lived isotopes have decayed prior to release. It also provides a 30-day holdup of these gases when refueling cold shutdown degassing is required.

System design provides that all the gaseous effluent from the degasifiers is directed to the gaseous waste charcoal delay subsystem for decay of most radioactive isotopes prior to compressing and discharged through the process vent. Gaseous effluent may be recycled to the volume control tank but this is not normally necessary. Provision is made to direct compressed waste gas to decay tanks for control of the equilibrium activity level of the coolant-fission-product-gas inventory and subsequent release to the atmosphere. The discharge to the atmosphere is handled by diluting the flow-controlled release of waste gas with a large volume of air, discharging the air through charcoal and HEPA filters to the top of the cooling tower, approximately 500 ft above the ground. This same discharge system is also designed to handle gaseous effluent from the main condenser air ejector vents, purge and vent from the oxygen analyzers, decay tank radiation monitor aerated vents of the vent and drain system, and the gaseous discharge from the containment vacuum system. The system also handles special conditions when gases from the containment purge are vented to the top of the cooling tower.

3.2 REFURBISHMENT ACTIVITIES

NRC

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

"...The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40-year license term will be from one of two broad categories: (1) SMITTR actions, most of which are repeated at regular intervals, and (2) major refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item...." (Ref. 3.1-21, Section 2.6.3.1, page 2-41.) ["SMITTR" is defined at GEIS Section 2.4, page 2-30, as surveillance, on-line monitoring, inspections, testing, trending, and recordkeeping.]

FENOC has addressed refurbishment activities in this environmental report in accordance with NRC regulations and supplementary information in the NRC GEIS for license renewal (Ref 3.1-21). NRC requirements for the renewal of operating licenses for nuclear power plants include the preparation of an integrated plant assessment (IPA) (10 CFR 54.21). The IPA must identify and list systems, structures, and components subject to an aging management review. Items that are subject to aging and might require refurbishment include, for example, the reactor vessel piping, supports, and pump casings (see 10 CFR 54.21 for details), as well as items that are not subject to periodic replacement.

NRC regulations for implementing the National Environmental Policy Act require environmental reports to describe in detail and assess the environmental impacts of refurbishment activities such as planned modifications to systems, structures, and components or plant effluents [10 CFR 51.53(c)(2)]. NRC regulations at 10 CFR Part 51 do not define "refurbishment," but GEIS Section 2.6.2.6 provides some examples of refurbishment activities and explains that these are actions that typically take place only once in the life of a nuclear plant, if at all (Ref. 3.1-21. Relevant examples of possible PWR refurbishment activities include replacing the turbine and turbine pedestal, steam generator, or reactor coolant system piping when these activities are carried out to ensure safe or more economic operations during the period of extended operations. The GEIS assumes, however, that refurbishment activities would take place during a "refurbishment period"; i.e., within the 10 years prior to current license expiration, over the course of numerous outages, and culminating in a major outage immediately prior to the extended (license renewal) term.

The FENOC aging management review, including the IPA conducted under 10 CFR Part 54, has identified a need for additional inspection at BVPS, including possible Unit 2 steam generator repair or replacement during the license renewal term. These inspection, repair and/or replacement activities would be scheduled during refueling or other outages and would be conducted as normal inspection, maintenance, repair, replacement and refueling activities. The environmental impacts of these activities would, therefore, be bounded by the impacts previously analyzed in the FES. FENOC's experience with the replacement of steam generators on BVPS Unit 1 supports the conclusion that these activities can be conducted as a part of a refueling outage without need for an extended outage of the type envisaged in the GEIS for refurbishment.

Therefore, FENOC does not have any plans to undertake any major refurbishment or replacement actions to maintain the functionality of important systems, structures, or components for purposes of license renewal that requires analysis in this ER. Routine replacement of components during the period of extended operation is expected to occur within the bounds of normal inspection and maintenance, including work advanced through the BVPS Steam Generator Tube Integrity Program. Modifications to improve operation of station systems, structures, or components are formally reviewed for potential environmental impacts by station personnel during the planning stage for the modification. Because these integrity and maintenance activities are not GEIS refurbishments, FENOC has not analyzed them further in this ER.

3.3 PROGRAMS AND ACTIVITIES FOR MANAGING THE EFFECTS OF AGING

NRC

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

"...The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40-year license term will be from one of two broad categories: (1) SMITTR actions, most of which are repeated at regular intervals, and (2) major refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item...." (Ref. 3.1-21, Section 2.6.3.1, page 2-41.) ["SMITTR" is defined at GEIS Section 2.4, page 2-30, as surveillance, on-line monitoring, inspections, testing, trending, and recordkeeping.]

In accordance with 10 CFR 54, FENOC has performed an aging management review of BVPS-1 and BVPS-2 and has included in the BVPS license renewal application an integrated plant assessment that identifies how FENOC would manage the effects of aging on systems, structures, and components during an extended period of plant operation. In some cases, existing BVPS programs adequately address aging effects with no license renewal modification. In other cases, FENOC has identified necessary modifications to existing programs or development and implementation of new programs.

Appendix A of the BVPS license renewal application includes supplements to the UFSARs for the units. In accordance with NRC requirements [10 CFR 54.21(d)], the supplements contain descriptions of the programs and activities for managing the effects of aging. In addition to describing existing programs, the supplements describe proposed modifications (enhancements) to existing programs and proposed programs and activities.

3.4 EMPLOYMENT

3.4.1 Current Workforce

FENOC employs a permanent workforce of approximately 1,000 employees and approximately 500 contractors at the BVPS site, a number that is within the range of 600 to 800 personnel per reactor unit that the NRC estimates in the GEIS (Ref. 3.1-21, Section 2.3.8.1). As shown in Table 3.4-1, approximately 59 percent of the permanent workforce lives in Beaver County and 24 percent lives in Allegheny County. The remaining employees live in various other locations.

FENOC refuels BVPS-1 and BVPS-2 at intervals of approximately 18 months. During refueling outages, site employment increases by as many as 800 workers for temporary (30 to 40 days) duty, and FENOC expects that similar increases would occur for refueling outages during the license renewal term. This is within the range of 200 to 900 additional workers per reactor outage cited by the NRC in the GEIS.

TABLE 3.4-1

COUNTIES OF RESIDENCE FOR PERMANENT WORKFORCE

County	State	Percentage of Workforce
Beaver	PA	58.55%
Allegheny	PA	23.79%
Columbiana	OH	5.84%
Butler	PA	3.85%
Lawrence	PA	2.42%
Washington	PA	2.14%
Hancock	WV	1.00%
Mahoning	OH	0.71%
Unknown	----	0.57%
Jefferson	PA	0.28%
Mercer	PA	0.28%
Crawford	PA	0.14%
Fayette	PA	0.14%
Stark	OH	0.14%
Trumbull	OH	0.14%

3.4.2 License Renewal Increment

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

The NRC assumes in the GEIS (Ref. 3.1-21, Section 2.6.2.7) that a renewed nuclear power plant operating license would be issued for a maximum of 20 years past the current license expiration date. The GEIS analysis further assumes that the utility would initiate SMITTR activities when the renewed license is issued and would conduct license renewal SMITTR activities throughout the remaining life of the plant, sometimes during full-power operation (Ref. 3.1-21, Section B.3.1.3), but mostly during normal refueling outages and 5-year and 10-year in-service inspection outages.

FENOC has determined that the GEIS scheduling assumptions are reasonably representative of BVPS incremental license renewal workload scheduling. Many SMITTR activities referred to in Section 3.3 would have to be performed during outages. Although some BVPS license renewal SMITTR activities would be one-time efforts, others would be recurring, periodic activities that would continue for the lives of the units.

The NRC cites estimates in the GEIS that 20 to 60 additional personnel per reactor would be needed to perform additional inspection, surveillance testing, and maintenance tasks during the license renewal term. The NRC uses the upper value of this range, 60 workers, in the GEIS as a conservative estimator of additional permanent workers needed per unit for license renewal SMITTR activities. GEIS Section C.3.1.2 was written using this approach in order to "...provide a realistic upper bound to potential population-driven impacts...."

FENOC expects that existing "surge" capabilities for routine activities, including refueling outages and 5- and 10-year in-service inspection outages, would enable FENOC to perform the increased SMITTR workload at the BVPS site without additional staff. Nonetheless, for the purpose of analyses in this ER, FENOC has adopted the NRC's GEIS approach as described, but assumes that 60 additional permanent personnel would accommodate the workload for both units. FENOC license renewal plant modifications would be SMITTR activities that would be performed mostly during outages, and FENOC would stagger BVPS outages so that both units would not be down at the same time. Therefore, as a reasonably conservative (high) estimate, FENOC assumes that BVPS would require 60 additional permanent workers to perform license renewal SMITTR activities rather than the 60 additional workers per reactor assumed by the NRC in the GEIS.

Adding full-time employees to the plant workforce for operating during the license renewal period would have the indirect effect of creating additional jobs and related population growth in the community. Using the Regional Input-Output Modeling System (RIMS II), the U.S. Bureau of Economic Analysis calculated a regional employment multiplier appropriate for the electric services (utilities) sector for the Pittsburgh MSA, which includes Allegheny, Beaver, Butler, Fayette, Washington, and Westmoreland Counties (Ref. 3.4-1). FENOC used this value (4.2471) to estimate the additional number of direct and indirect jobs during the license renewal period for the analysis assumption discussed above. Applying the multiplier, a total of 255 (60×4.2471) new jobs would be created in the area. Stated differently, FENOC assumes that 60 additional permanent direct workers during the license renewal period would create an additional 195 indirect jobs in the community. These 255 new direct and indirect jobs represent less than 1 percent of the current labor force of the Beaver and Allegheny combined-county area (703,000 workers; see Section 2.6).

Conservatively assuming that each direct and indirect job is filled by an in-migrating worker, these 255 new jobs (60 direct and 195 indirect) could result in a population increase of 632 in the area [255 jobs multiplied by 2.48 average number of persons per household in the commonwealth of Pennsylvania (Ref. 3.4-2). This increase represents less than 0.1 percent of the USCB's estimated population in year 2000 (1,463,078) for the combined area of Beaver and Allegheny Counties.

3.5 REFERENCES

Note to reader: This list of references identifies web pages and associated URLs where reference data was obtained. Some of these web pages may likely no longer be available or their URL addresses may have changed. FENOC has maintained hard copies of the information and data obtained from the referenced web pages.

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3.1-4 FirstEnergy Nuclear Operating Company. *Beaver Valley Power Station Unit 1 Updated Safety Analysis Report, Revision 23.*

3.1-5 FirstEnergy Nuclear Operating Company. *Beaver Valley Power Station Unit 2 Updated Final Safety Analysis Report, Revision 16.*

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3.1-8 FirstEnergy Nuclear Operating Company. *Beaver Valley Uprating Licensing Report.* Document No. 6027R1-1.doc–082902. August 2002.

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3.1-12 Federal Emergency Management Agency. *Flood Insurance Study, Borough of Shippingport, Pennsylvania, Beaver County*. August 19, 1991.

3.1-13 Duquesne Light Company. *Beaver Valley Power Station Unit 1 Operating Manual, Chapter 30, River Water System*: 1 OM-30.1.B, Revision 5 and 1 OM-30.1.C, Revision 10, July 2002.

3.1-14 Duquesne Light Company. *Beaver Valley Power Station Unit 2 Environmental Report – Operating License Stag*e, Amendment 6. May 1984.

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3.1-16 Duquesne Light Company. "Beaver Valley Power Station No. 1 & 2, Waste Water Flow Diagram." 8700-RM-0027F, Rev. 13, Addendum 1. January 14, 2003.

3.1-17 U.S. Army Corps of Engineers. "Daily average temperature data for the Ohio River at Montgomery Locks and Dam for period of record 1988-2002." Provided to Jonathan Yost, EA Engineering. October 4, 2002.

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4.0 ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION AND MITIGATING ACTIONS

NRC

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

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

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

4.1 INTRODUCTION

Chapter 4 presents an assessment of the environmental consequences and potential mitigating actions associated with the renewal of the Beaver Valley Power Station (BVPS) Units 1 & 2 operating licenses. The assessment tiers from NRC's *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (Ref. 4.1-1), which identifies and analyzes 92 environmental issues that NRC considers to be associated with nuclear power plant license renewal. In its analysis, NRC designated each of the 92 issues as Category 1, Category 2, or NA (not applicable) and required plant-specific analysis of only the Category 2 issues.

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

- the environmental impacts associated with the issue were 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) was assigned to the impacts that would occur at any plant, regardless of which plant was 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 was considered in the analysis, and it was determined additional plant-specific mitigation measures are likely to be not sufficiently beneficial to warrant implementation.

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

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

4.1.1 Category 1 License Renewal Issues

NRC
"The environmental report for the operating license renewal stage is not required to contain analyses of the environmental impacts of the license renewal issues identified as Category 1 issues in Appendix B to subpart A of this part." [10 CFR 51.53(c)(3)(i)]
"...[A]bsent new and significant information, the analysis for certain impacts codified by this rulemaking need only be incorporated by reference in an applicant's environmental report for license renewal...." (61 Federal Register, page 28483)

FENOC has determined that of the 69 Category 1 issues, eight do not apply to the BVPS site because they apply to design, operational, or location features that do not exist at the facility (Attachment A, Table A-1). FENOC has reviewed the NRC analysis presented in the GEIS and has not identified or become aware of any new and significant information that would alter the NRC conclusions or would make the analysis inapplicable to BVPS-1 and BVPS-2 (see Section 5.0). Therefore, FENOC adopts by reference the NRC findings for the 61 Category 1 issues that FENOC determined to be applicable to the BVPS site.

4.1.2 Category 2 License Renewal Issues

NRC

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

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

In the GEIS, the NRC designated 21 issues as Category 2. Sections 4.2 through 4.21 addresses each of these issues (Section 4.18 addresses two issues), beginning with a statement of the issue. As is the case with Category 1 issues, some Category 2 issues apply to design, operational, or location features that BVPS does not have. If an issue does not apply to BVPS, the section explains the basis for inapplicability.

For the 15 Category 2 issues that FENOC has determined to be applicable to BVPS, analyses are provided. These analyses include conclusions regarding the significance of the impacts relative to the renewal of the BVPS Units 1 & 2 operating licenses and, when applicable, discuss potential mitigative alternatives. FENOC 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 NRC has concluded that those impacts that do not exceed permissible levels in the NRC's regulations are considered small.
>
> MODERATE - Environmental effects are sufficient to alter noticeably but not to destabilize any important attribute of the resource.
>
> LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize any important attributes of the resource.

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

4.1.3 "NA" License Renewal Issues

NRC determined that its categorization and impact-finding definitions did not apply to two issues (Issues 60 and 92); however, FENOC included these issues in Attachment A. Applicants currently do not need to submit information on chronic effects from electromagnetic fields (10 CFR 51, Appendix B, Table B-1, Footnote 5). For environmental justice, NRC does not require information from applicants, but noted that it will be addressed in individual license renewal reviews (10 CFR 51, Appendix B, Table B-1, Footnote 6). The NRC has indicated that applicants should include in the environmental report pertinent information to support an environmental justice review by the NRC (Ref. 4.1-2, Section 4.22). Therefore, FENOC has included minority and low-income demographic information in Section 2.5.2.

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

NRC

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

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

The NRC made surface water use conflicts a Category 2 issue because surface water withdrawals from small rivers could adversely impact aquatic life and downstream users of the small river, and consultations with regulatory agencies indicate that water use conflicts are already a concern at two closed-cycle plants (Limerick and Palo Verde) and may be a problem in the future at other plants. In the GEIS, NRC notes two factors that may cause water use and availability issues to become important for some nuclear power plants that use cooling towers. First, some plants equipped with cooling towers are located on small rivers that are susceptible to droughts or competing water uses. Second, consumptive water loss associated with closed-cycle cooling systems may represent a substantial proportion of the flows in small rivers. Loss of a substantial portion of flow from a small stream as a result of evaporative losses from a cooling tower would reduce the amount of habitat for fish and aquatic invertebrates (Ref. 4.1-1, Section 4.3.2.1). Consumptive water use can adversely impact riparian vegetation and associated animal communities by reducing the amount of water in the stream that is available for plant growth, maintenance, and reproduction.

BVPS-1 and BVPS-2 operate with closed-cycle cooling systems equipped with cooling towers, and makeup water for these systems is withdrawn from the New Cumberland Pool of the Ohio River (Section 3.1.3). As indicated in Table 2.2-1, the annual average flow of the Ohio River at the BVPS site is 39,503 cubic feet per second (cfs) (1.25×10^{12} cubic feet per year), which meets NRC's annual flow criterion for classification as a small river.

The results of FENOC's analysis presented in Section 2.2.1.2 indicates that the once in 10 year, 7-day duration low flow (7Q10) in the Ohio River at the BVPS site is approximately 5,200 cfs. Based on estimates from the U.S. Army Corps of Engineers, the minimum expected flow under conditions corresponding to the lowest flow of record, which occurred in 1930, is approximately 4,000 cfs (Section 2.2.1.2).

Consumptive water losses resulting from BVPS operation comprise a very small fraction of flow in the Ohio River, even under low flow conditions. FENOC estimates that the maximum consumptive loss that would occur if both BVPS-1 and BVPS-2 were operated at their maximum permitted power level (2,900 MWt per unit) would be approximately 45 cfs (Section 3.1.3), or

0.9 percent and 1.1 percent of the 7Q10 and minimum expected flow of the Ohio River, respectively.

As FENOC indicated in Section 2.2.1.2, the USACE's flow control strategy includes maintaining a minimum pool level in New Cumberland Pool of 664.5 feet NGVD for navigation under postulated flows as low as 800 cfs, and USACE does not anticipate a change in this policy in the foreseeable future. Therefore, FENOC does not anticipate that consumptive losses as a result of BVPS operation would result in any change in the elevation of the New Cumberland Pool.

FENOC's environmental review efforts, which included discussion with USACE, water authority representatives, and regulatory and planning agencies (see Sections 2.2 and 5.0) did not identify any projects upstream from BVPS or on the New Cumberland Pool planned for the near future that would significantly reduce river flow. However, as discussed in Section 2.2.1.3, future development in the watershed of consumptive-use facilities such as large power plants that use closed-cycle cooling could reduce available flows in the long term. Similarly, the USACE has indicated that proposals have been made to conduct reallocation studies on two reservoirs upstream that could result in some reduction in summer low flows (see Section 2.2.1.4). However, in view of the USACE's control strategy, these actions are not expected to result in any change to levels of the navigation pools on the upper Ohio River.

Instream and riparian communities near the New Cumberland Pool have been identified in Sections 2.3.1.2 through 2.3.1.4. In general, increases in species diversity have been noted for these communities attributed to increased water and habitat quality in the Ohio River watershed upstream of the New Cumberland Pool. Withdrawal at the New Cumberland Pool by the BVPS has resulted in a SMALL change in pool depth as described above. Therefore, the subsequent impact on the riparian and instream communities would be minimal due to slight changes in pool depth even at 7Q10 low flows as addressed in 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 13.

In view of these considerations, FENOC concludes that consumptive losses of water from the Ohio River would not significantly reduce river flow or affect water surface elevation of the New Cumberland Pool, and therefore would have no impact on aquatic or riparian ecological communities described in Section 2.3 of this environmental report. Because the definition of "SMALL" includes impacts that are not detectable, the appropriate characterization of the impacts from consumptive water use is SMALL, and further mitigation would be unwarranted.

4.3 ENTRAINMENT OF FISH AND SHELLFISH IN EARLY LIFE STAGES

NRC

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

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

NRC made impacts on fish and shellfish resources from entrainment a Category 2 issue because it could not assign a single significance level (small, moderate, or large) to the issue. The impacts of entrainment are small at many facilities, but may be moderate or large at others. In addition, ongoing restoration efforts may increase the number of fish susceptible to intake effects during the license renewal period (Ref. 4.1-1, Section 4.2.2.1.2). Information needing to be ascertained includes (1) type of cooling system (whether once-through or cooling pond), and (2) status of Clean Water Act (CWA) Section 316(b) determination or equivalent state documentation.

The issue of entrainment of fish and shellfish in early life stages does not apply to BVPS because the station does not utilize once-through cooling or cooling pond heat dissipation systems.

4.4 IMPINGEMENT OF FISH AND SHELLFISH

NRC

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

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

NRC made impacts on fish and shellfish resources from impingement a Category 2 issue, because it could not assign a single significance level to the issue. Impingement impacts are small at many facilities, but might be moderate or large at other plants (Ref. 4.1-1, Section 4.2.2.1.3). Information that needs to be ascertained includes (1) type of cooling system (whether once-through or cooling pond), and (2) current CWA 316(b) determination or equivalent state documentation.

The issue of impingement of fish and shellfish does not apply to BVPS because the station does not utilize once-through cooling or cooling pond heat dissipation systems.

4.5 HEAT SHOCK

NRC

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act... 316(a) variance in accordance with 40 CFR 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 ...." [10 CFR 51.53(c)(3)(ii)(B)]

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

NRC made impacts on fish and shellfish resources resulting from heat shock a Category 2 issue, because of continuing concerns about thermal discharge effects and the possible need to modify thermal discharges in the future in response to changing environmental conditions (Ref. 4.1-1, Section 4.2.2.1.4). Information to be ascertained includes: (1) type of cooling system (whether once-through or cooling pond), and (2) evidence of a CWA Section 316(a) variance or equivalent state documentation.

The issue of heat shock does not apply to BVPS because the station does not utilize once-through cooling or cooling pond heat dissipation systems.

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

NRC
"If the applicant's plant...pumps more than 100 gallons (total onsite) of ground water per minute, an assessment of the impact of the proposed action on groundwater use must be provided." [10 CFR 51.53(c)(3)(ii)(C)]
"...Plants that use more than 100 gpm may cause ground-water use conflicts with nearby ground-water users...." [10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 33]

NRC made this groundwater use conflict a Category 2 issue because overuse of an aquifer could exceed the natural recharge. Locally, a withdrawal rate of more than 100 gallons per minute (gpm) could create a cone of depression that could extend offsite. This could inhibit the withdrawal capacity of nearby offsite users.

As described in Section 3.1.3, no groundwater is used at BVPS, and no future use of groundwater is anticipated. Therefore, the issue of groundwater use conflicts (plants using more than 100 gpm groundwater) does not apply.

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

NRC

"If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×1012 ft3 / year...[t]he applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow." [10 CFR 51.53(3)(ii)(A)]

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

NRC made this groundwater use conflicts a Category 2 issue because surface water withdrawals from small rivers could adversely impact groundwater-aquifer recharge. This is a particular concern during low-flow conditions and could create a cumulative impact due to upstream consumptive use. Cooling towers and cooling ponds lose flow by evaporation, which is necessary to cool the heated water before it is discharged to the environment.

The issue of groundwater use conflicts applies because BVPS-1 and BVPS-2 operate with closed-cycle cooling systems equipped with cooling towers that withdraw makeup water from the New Cumberland Pool of the Ohio River (Section 3.1.3). As indicated in Table 2.2-1, the annual average flow of the Ohio River at the BVPS site is 39,503 cubic feet per second (cfs); or 1.25×10^{12} cubic feet per year, which meets NRC's annual flow criterion for classification as a small river. Circulated cooling water lost to cooling tower evaporation is replaced by make-up water pumped from the Ohio River.

The results of FENOC's analysis presented in Section 2.2.1.2 indicates that the once in 10 year, 7-day duration low flow (7Q10) in the Ohio River at the BVPS site is approximately 5,200 cfs. Based on estimates from the U.S. Army Corps of Engineers, the minimum expected flow under conditions corresponding to the lowest flow of record, which occurred in 1930, is approximately 4,000 cfs (Section 2.2.1.2).

Consumptive water losses resulting from BVPS operation comprise a very small fraction of flow in the Ohio River, even under low flow conditions. FENOC estimates that the maximum consumptive loss that would occur if both BVPS-1 and BVPS-2 were operated at their maximum permitted power level (2,900 MWt per unit) would be approximately 59 cfs (Section 3.1.3), or 1.1 percent and 1.5 percent of the 7Q10 and minimum expected flow of the Ohio River, respectively.

As FENOC indicated in Section 2.2.1.2, the USACE's flow control strategy includes maintaining a minimum pool level in New Cumberland Pool of 664.5 feet NGVD for navigation under postulated flows as low as 800 cfs, and USACE does not anticipate a change in this policy in the foreseeable future. Therefore, FENOC does not anticipate that consumptive losses as a result of BVPS operation would result in any change in the elevation of the New Cumberland Pool.

FENOC's environmental review efforts, which included discussion with USACE, water authority representatives, and regulatory and planning agencies (see Sections 2.2 and 5.0) did not identify any projects upstream from BVPS or on the New Cumberland Pool planned for the near future that would significantly reduce river flow. However, as discussed in Section 2.2.1.3, future development in the watershed of consumptive-use facilities such as large power plants that use closed-cycle cooling could reduce available flows in the long term. Similarly, the USACE has indicated that proposals have been made to conduct reallocation studies on two reservoirs upstream that could result in some reduction in summer low flows (see Section 2.2.1.4). However, in view of the USACE's control strategy, these actions are not expected to result in any change to levels of the navigation pools on the upper Ohio River.

Alluvial groundwater aquifer recharge and depth near the New Cumberland Pool has been documented to fluctuate with the changes in pool depth in the 1970's (Ref. 2.1-4, Section 2.5.4.6). These changes were documented regarding pool depth in the 1970s (Ref. 2.1-4, Section 2.5.4.6). As described above, the pool depth as monitored by the USACE is not estimated to change or have a significant impact due to operations at the BVPS even at 7Q10 flows. Subsequently, impacts on the alluvial aquifer near the New Cumberland Pool are not expected to occur. Thus, water use conflicts are not expected to occur, as addressed in 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 34, based on existing demand for withdrawal from the aquifer as described above.

In view of these considerations, FENOC concludes that consumptive losses of water from the Ohio River would not significantly reduce river flow or affect water surface elevation of the New Cumberland Pool, and therefore would have no impact on associated alluvial aquifers described in Section 2.2 of this environmental report. Because the definition of "SMALL" includes impacts that are not detectable, the appropriate characterization of the impacts from consumptive water use is SMALL, and further mitigation would be unwarranted.

4.8 GROUNDWATER USE CONFLICTS (PLANTS USING RANNEY WELLS)

NRC

"If the applicant's plant uses ranney wells...an assessment of the impact of the proposed action on groundwater use must be provided." [10 CFR 51.53(C)(3)(II)(C)]

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

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

The issue of groundwater use conflicts does not apply to BVPS because the plant does not use Ranney wells. As Section 3.1.3 describes, BVPS uses a closed cycle cooling system with cooling towers that removes make-up water from the Ohio River and discharges blowdown to the Ohio River.

4.9 DEGRADATION OF GROUNDWATER QUALITY

NRC
"If the applicant's plant is located at an inland site and utilizes cooling ponds, an assessment of the impact of the proposed action on groundwater quality must be provided." [10 CFR 51.53(c)(3)(ii)(D)]
"...Sites with closed-cycle cooling ponds may degrade ground-water quality. For plants located inland, the quality of the ground water in the vicinity of the ponds must be shown to be adequate to allow continuation of current uses...." [10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 30]

NRC made degradation of groundwater quality a Category 2 issue because evaporation from closed-cycle cooling ponds concentrates dissolved solids in the water and settles suspended solids. In turn, seepage into the water table aquifer could degrade groundwater quality.

The issue of groundwater degradation does not apply to BVPS because the plant does not use cooling ponds. As Section 3.1.3 describes, BVPS uses a closed cycle cooling system with cooling towers that withdraws make-up water from the Ohio River and discharges blowdown to the Ohio River.

4.10 IMPACTS OF REFURBISHMENT ON TERRESTRIAL RESOURCES

NRC

The environmental report must contain an assessment of "...the impact of refurbishment and other license-renewal-related construction activities on important plant and animal habitats...." [10 CFR 51.53(c)(3)(ii)(E)]

"...Refurbishment impacts are insignificant if no loss of important plant and animal habitat occurs. However, it cannot be known whether important plant and animal communities may be affected until the specific proposal is presented with the license renewal application...." [10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 40]

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

NRC made impacts of refurbishment on terrestrial resources a Category 2 issue because the significance of ecological impacts cannot be determined without considering site-specific and project-specific refurbishment details (Ref. 4.1-1, Section 3.6). Aspects of the site and the project to be ascertained are (1) the identification of important ecological resources, (2) the nature of refurbishment activities, and (3) the extent of impacts to plant and animal habitat.

As discussed in Section 3.2 of this ER, FENOC does not plan to undertake major refurbishment for BVPS license renewal. FENOC concludes that there would be no refurbishment-related impacts to terrestrial resources, and no analysis is required.

4.11 THREATENED OR ENDANGERED SPECIES

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

The NRC made impacts to threatened and endangered species a Category 2 issue because the status of many species is being reviewed, and a site-specific assessment is required to determine whether any identified species could be affected by refurbishment activities or continued plant operations through the renewal period. In addition, compliance with the Endangered Species Act requires consultation with the appropriate federal agency (Ref. 4.1-1, Sections 3.9 and 4.1). Information pertinent to this assessment, set forth in Table 4.11-1, includes: (a) actual or potential occurrence of threatened or endangered species on or in the vicinity of the BVPS site and associated transmission lines that are in the scope of BVPS license renewal, (b) impact initiators presented by continued operation of BVPS and these transmission lines that could affect threatened or endangered species that do or may occur, (c) controls established for impact initiators, and (d) industry and plant experience related to potential impacts.

4.11.1 Refurbishment

As discussed in Section 3.2 of this ER, FENOC does not plan to undertake major refurbishment for BVPS license renewal. FENOC concludes that there would be no refurbishment-related impacts to threatened and endangered species, and no analysis is required.

4.11.2 License Renewal Term

FENOC's assessment presented in this section is therefore limited to potential impacts from operation during the license renewal period of BVPS and transmission line segments addressed in this environmental report. These transmission lines, the Beaver Valley – Crescent Line 318 and three reconfiguration segments, are more fully described in Section 3.1.4 and are depicted in Figures 3.1-2 and 3.1-3. Section 3.1.4 also describes transmission facilities and corridor inspection and maintenance practices. Land use along the line is described in Section 2.3.2. Although the NRC's license renewal regulations at 10 CFR 51.53(c)(3)(ii)(E) requires only an assessment of impact on species protected under the federal Endangered Species Act, FENOC also addresses in this assessment those species designated as endangered, threatened, or candidates for such listing by the Commonwealth of Pennsylvania.

FENOC identified in Section 2.3.3 and Table 2.3-2 threatened, endangered, and candidate species of potential concern to BVPS license renewal and the likelihood of their occurrence in the vicinity of the BVPS site or Beaver Valley-Crescent Line 318. Table 4.11-1 summarizes this information.

The assessment presented in Table 4.11-1 includes consideration of input received in response to contacts FENOC made with the FWS, Pennsylvania Game Commission, Pennsylvania Fish and Boat Commission, and Pennsylvania Department of Conservation and Natural Resources specifically in regard to threatened or endangered species, and with the Ohio Department of Natural Resources and West Virginia Division of Natural Resources as part of BVPS license renewal new and significant information review activities (discussed in Chapter 5.0). Attachment B includes copies of the contact letters sent to the FWS and Pennsylvania resource agencies and responses received from these agencies. In December, 2006, FENOC sent letters to the FWS, Pennsylvania Game Commission, Pennsylvania Fish and Boat Commission, and Pennsylvania Department of Conservation and Natural Resources, inviting each agency to provide input into the license renewal environmental report review process, and specifically to identify to FENOC any concerns of the agency regarding license renewal or any information that could potentially be new and significant. No agency raised issues or questions.

Based on the impact assessment presented in Table 4.11-1, including the results of correspondence with agencies, FENOC concludes that impact to threatened and endangered species from continued operation of BVPS-1 and BVPS-2 in the license renewal period would be SMALL, and further mitigation would be unwarranted.

TABLE 4.11-1

SUMMARY IMPACT ASSESSMENT FOR THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL

Invertebrates

Species and Status[a, b]

Northern riffleshell (*Epioblasma torulosa rangiana*), FE, PE

Clubshell (*Pleurobema clava*), FE, PE

Occurrence Potential[a]

None to Low. Last documented occurrence in the upper Ohio River or lower Allegheny River in early 1900s. However, recent surveys have documented the presence in the New Cumberland Pool, including the Phillis Island backchannel, of other unionid mussel species not recorded there since the early 1900s, and indicate that some mussels listed by PA or FWS may recolonize upper Ohio River pools in the future.

Impact Initiators

Maintenance dredging (e.g., barge slip); cooling water and wastewater discharges; petroleum or hazardous materials spills/unplanned releases.

Additional Impact Considerations and Conclusions[c]

- Maintenance dredging is regulated by USACE and PADEP permits. Cooling water and wastewater discharges are regulated by NPDES permit, which includes discharge limits and monitoring requirements. Controls are established for prevention, preparedness, and response to spills and unplanned releases (e.g., *BVPS Preparedness, Prevention, and Contingency Plan*).
- Closed-cycle cooling, tendency of plume to remain at surface, and low probability of simultaneous shutdown of both BVPS units reduces potential for adverse thermal impacts.
- Unionid mussel population increase or recolonization at Phillis Island, downstream from BVPS outfall, apparently has occurred since BVPS initiated operation.
- Benthic macroinvertebrate annual monitoring at BVPS (1973 through present) indicates that BVPS is not adversely affecting the benthic macroinvertebrate community. The NRC concurred and deleted the requirement for benthic macroinvertebrate monitoring in 1980 with Amendment 25 to the BVPS-1 Technical Specifications (Ref. 4.11-1).
- FENOC has not identified any significant land disturbing activities of natural habitats that would be undertaken for license renewal either on or in the vicinity of the BVPS site or along the Beaver Valley-Crescent Line 318 corridor.
- Results of PNDI searches (Ref. 4.11-2 through Ref. 4.11-7) have not identified these or other listed or candidate invertebrate species within PFBC jurisdiction as potential conflicts with BVPS or transmission line operation.
- Based on their review of a BVPS license renewal activities summary, ODNR has determined that there will be no new and significant environmental implications in Ohio resulting from BVPS license renewal (Ref. 4.11-8). WVDNR indicated that they have no known occurrences of any rare, threatened, endangered, of special concern species in the vicinity of BVPS, nor do they have information indicating that WV wildlife resources have been affected by BVPS operations (Ref. 4.11-9).

TABLE 4.11-1 (CONTINUED)

SUMMARY IMPACT ASSESSMENT FOR THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL

Invertebrates (continued)

Additional Impact Considerations and Conclusions[c]

- FWS indicates that, except for occasional transient species, no federally listed or proposed threatened or endangered species are known to occur within the project impact area (Attachment B).
- PFBC response to FENOC's preliminary impact assessment raised no concern about BVPS license renewal with respect to these species (Attachment B).

Impact Conclusion: SMALL

Fish

Species and Status[a, b]

Silver chub (*Macrhybopsis storeriana*), PE	Mooneye (*Hiodon tergisus*), PT	Brook silverside (*Labidesthes sicculus*), PC
Skipjack herring (*Alosa chrysochloris*), PT	Smallmouth buffalo (*Ictiobus bubalus*), PT	Longnose gar (*Lepisosteus osseus*), PC
Goldeye (*Hiodon alosoides*), PT	Channel darter (*Percina copelandi*), PT	River redhorse (*Moxostoma carinatum*), PC

Occurrence Potential[a]

Various (see Table 2.3-2). Presence of all of these species in the New Cumberland Pool since 1990 has been documented. Silver chub, skipjack herring, smallmouth buffalo, and longnose gar have been recently collected with relatively high frequency and/or in relatively high abundance. Pollution-intolerant species such as mooneye, goldeye, skipjack herring, and river redhorse have reportedly increased in the upper Ohio River consistent with improvements in water quality.

Impact Initiators

Maintenance dredging (e.g., barge slip); cooling water and wastewater discharges; petroleum or hazardous materials spills/unplanned releases; entrainment of early life stages in cooling water; impingement of fish on intake screens.

Additional Impact Considerations and Conclusions[c]

- Maintenance dredging is regulated by USACE and PADEP permits. Cooling water and wastewater discharges are regulated by NPDES permit, which includes discharge limits and monitoring requirements. Controls are established for prevention, preparedness, and response to spills and unplanned releases (e.g., *BVPS Preparedness, Prevention, and Contingency Plan*). Closed-cycle cooling reduces potential for impact from impingement, entrainment, and thermal impacts. Under normal operating conditions, BVPS units are not shut down simultaneously, reducing potential for impact from cold shock.

TABLE 4.11-1 (CONTINUED)

SUMMARY IMPACT ASSESSMENT FOR THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL

Fish (continued)

Additional Impact Considerations and Conclusions[c]

- Increase in populations of some of these species has apparently occurred since BVPS initiated operation. Annual monitoring of the fish community at BVPS indicates presence of special-status fish species at both control and non-control stations (see Table 2.3-2). Monitoring conducted at BVPS from 1976 through 1995, indicated that entrainment of fish eggs and larvae impacts were not significant and impingement losses were small and had little impact on populations in the river. The NRC concurred and deleted these monitoring requirements in 1980 with Amendment 25 to the BVPS-1 Technical Specifications; however, monitoring was continued on voluntary basis until 1995 (Ref. 4.11-1). Review of BVPS annual monitoring reports (Ref. 4.11-10) and the BVPS-2 Operating License Stage ER (Ref. 4.11-11, Table 2.2-17) indicates that none of these species were specifically identified in fish egg and larvae samples collected during entrainment monitoring, and that the only incidences of impingement of these species noted in impingement monitoring conducted from 1980 through 1995 were: 2 silver chubs found dead on the screens in 1988, 1 in an operating bay and 1 in a non-operating bay; 1 live channel darter found on an intake screen in 1983; and smallmouth buffalo noted in impingement samples in 1994.
- Results of PNDI searches and associated species impact reviews by PFBC (Ref. 4.11-2 through Ref. 4.11-7), conducted at FENOC's request, identified these species as potential conflicts with BVPS operation and crossings of the Ohio River by BVPS-associated transmission lines. PFBC (Ref. 4.11-3; Ref. 4.11-6) indicated that these species are vulnerable to physical and chemical changes to their aquatic environment, and that if environmentally invasive activities will affect any waterways at the site, additional information would be required for a more thorough PFBC evaluation. PFBC further indicated that if there will be no disturbance or impacts to waterways, and provided that if best management practices are used and an approved strict erosion/sedimentation control plan is maintained, then no significant adverse impacts to rare or protected species under PFBC jurisdiction are anticipated.
- FENOC has not identified any significant land disturbing activities of natural habitats that would be undertaken for license renewal either on or in the vicinity of the BVPS site or along the Beaver Valley-Crescent Line 318 corridor, and notes that effective controls (summarized above) are in place to minimize potential for operational impacts.
- Based on their review of a BVPS license renewal activities summary, ODNR has determined that there will be no new and significant environmental implications in Ohio resulting from BVPS license renewal (Ref. 4.11-8). WVDNR indicated that they have no known occurrences of any rare, threatened, endangered, of special concern species in the vicinity of BVPS, nor do they have information indicating that WV wildlife resources have been affected by BVPS operations (Ref. 4.11-9).
- FWS indicates that, except for occasional transient species, no federally listed or proposed threatened or endangered species are known to occur within the project impact area (Attachment B).
- PFBC response to FENOC's preliminary impact assessment for these species requested additional information regarding avoidance measures for fish impingement and entrainment, which FENOC provided (Attachment B).

Impact Conclusion: SMALL

TABLE 4.11-1 (CONTINUED)

SUMMARY IMPACT ASSESSMENT FOR THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL

Plants

Species and Status[a, b]

Small whorled pogonia (*Isotria medeoloides*), FT, PE

Eastern blue-eyed grass (*Sisyrinchium atlanticum*),PE

Tall larkspur (*Delphinium exaltatum*), PE

Purple rocket (*Iodanthus pinnatifidus*), PE

Harbinger-of-spring (*Erigenia bulbosa*),PT

Occurrence Potential[a]

Small whorled pogonia: None to Low on BVPS site, and Low on or near Beaver Valley – Crescent Line 318 corridor. Documented as not observed during 1974–1975 BVPS site ecological surveys. Not reported in PNDI searches for either BVPS site or transmission corridor. None currently known from southwestern Pennsylvania.

Remaining plant species: Low on BVPS site; Moderate to High in the vicinity of Beaver Valley-Crescent Line-318 corridor. PNDI searches indicate occurrence records for these species only in the vicinity of the transmission corridor; records for purple rocket and harbinger-of-spring are recent (Ref. 4.11-4; Ref 4.11-5; Ref. 4.11-7).

Impact Initiators

Vegetation maintenance on BVPS site and transmission line corridor.

Additional Impact Considerations and Conclusions[c]

- FENOC and Duquesne Light maintenance practices on transmission corridors are limited to selective pruning or removal of trees that could interfere with the line and selective pruning or herbicide use to control incompatible vegetation. EPA-approved herbicides are selectively applied in accordance with manufacturer's label requirements by state-licensed applicators. Maintenance practices on the BVPS site are similar to maintain cleared areas for site security.
- FENOC has not identified any land disturbing activities of natural habitats that would be undertaken for license renewal.
- Neither FENOC nor Duquesne Light is aware of any adverse impact to any threatened, endangered, or candidate plant species from past or current operation of BVPS or transmission lines being considered in the license renewal environmental review.
- Forested areas within the Beaver Valley-Crescent Line 318 corridor exist only on lower slopes and bottoms of some spanned ravines and valleys and along the corridor edge in some segments, reducing potential for disturbance of potentially compatible habitat for the small whorled pogonia and state-listed woodland species (see Table 2.3-2).
- PNDI/PDCNR review for the Allegheny County portion of the Beaver Valley-Crescent Line 318 corridor, which identified occurrence records for Eastern blue-eyed grass and tall larkspur, concluded that that continued operation of this line would pose no conflicts with these plant species (Ref. 4.11-4; Attachment B).

TABLE 4.11-1 (CONTINUED)

SUMMARY IMPACT ASSESSMENT FOR THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL

Plants (continued)

Additional Impact Considerations and Conclusions[c]

- PNDI/PDCNR review for the Beaver County portion of the Beaver Valley-Crescent Line 318 corridor, which identified occurrence records for purple rocket and harbinger-of-spring, indicates that license renewal would pose no conflict with these plant species if it does not involve land-disturbing activity (Ref. 4.11-7; Attachment B).
- FWS indicates that, except for occasional transient species, no federally listed or proposed threatened or endangered species are known to occur within the project impact area (Attachment B).

Impact Conclusion: SMALL

Birds

Species and Status[a, b]

Bald Eagle (*Haliaeetus leucocephalus*), FT, PE

Short-eared Owl (*Asio flammeus*), PE

Peregrine Falcon (*Falco peregrinus*), PE

Occurrence Potential[a]

Bald Eagle: High for transient or foraging individuals. Occasional individuals are observed along the Ohio River at the BVPS site. None to Low for future nesting on or near BVPS site considering industrial development and human activity. Low to Moderate for future nesting along Beaver Valley-Crescent Line 318 transmission corridor considering undeveloped areas near Ambridge Reservoir.

Peregrine Falcon: Moderate for transient or foraging individuals. None to Low for nesting considering habitat availability.

Short-eared Owl: Moderate for transient or foraging individuals. None for nesting on BVPS site. Low to moderate for nesting on or near Beaver Valley-Crescent Line 318 transmission corridor considering habitat availability.

Impact Initiators

Collision with cooling towers or transmission lines.

TABLE 4.11-1 (CONTINUED)

SUMMARY IMPACT ASSESSMENT FOR THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL

Birds (continued)

Additional Impact Considerations and Conclusions[c]

- Fall and Spring surveys of bird collisions at the BVPS-1 cooling tower (1974 through 1978) found a total of only 27 dead birds (Ref. 4.11-13).
- FirstEnergy and Duquesne Light are not aware of any reports of impact or electrocutions of these species associated with Beaver Valley-Crescent Line 318 or transmission line relocations addressed in the BVPS license renewal environmental review.
- Results of PNDI searches (Ref. 4.11-2 through Ref. 4.11-7), conducted at FENOC's request, have not identified these or other listed or candidate species under PA Game Commission jurisdiction as potential conflicts with BVPS or transmission line operation. PA Game Commission (Ref. 4.11-12) indicates that, except for occasional transient individuals, BVPS is not located in an area that is habitat for an endangered or threatened bird under their jurisdiction, nor are any long-term adverse impacts to associated critical or unique habitats anticipated from BVPS operation.
- Based on their review of a BVPS license renewal activities summary, ODNR has determined that there will be no new and significant environmental implications in Ohio resulting from BVPS license renewal (Ref. 4.11-8); WVDNR indicated that they have no known occurrences of any rare, threatened, endangered, of special concern species in the vicinity of BVPS, nor do they have information indicating that WV wildlife resources have been affected by BVPS operations (Ref. 4.11-9).
- FWS indicates that, except for occasional transient species, no federally listed or proposed threatened or endangered species are known to occur within the project impact area (Attachment B).
- PA Game Commission office review conducted in response to preliminary impact assessments for these species (Attachment B) determined that, except for occasional transient individuals, BVPS license renewal should not affect endangered or threatened bird or mammal species recognized by that agency, nor would license renewal be expected to result in adverse impact to any critical or unique habitats.

Impact Conclusion: SMALL

Mammals

Species and Status[a, b]

Indiana bat (*Myotis sodalis*), FE, PE

Occurrence Potential[a]

None for hibernating colonies. Low for maternal colonies on BVPS site. Not collected or observed in 1974-75 ecological surveys of BVPS site. Low for maternal colonies in trees bordering Beaver Valley-Crescent Line 318 transmission corridor.

Impact Initiators

Removal of maternal colony trees bordering transmission corridor.

TABLE 4.11-1 (CONTINUED)

SUMMARY IMPACT ASSESSMENT FOR THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL

Mammals (continued)

Additional Impact Considerations and Conclusions[c]

- Corridor maintenance practices limit removal of mature trees to those that could interfere with transmission lines.
- Streams along corridor are frequently in relatively deep narrow valleys that are spanned, reducing the necessity to clear riparian trees.
- Results of PNDI searches (Ref. 4.11-2 through Ref. 4.11-7) conducted at FENOC's request have not identified this or other mammal species under PA Game Commission jurisdiction as potential conflicts with BVPS or transmission line operation. PA Game Commission (Ref. 4.11-12) indicates that, except for occasional transient individuals, BVPS is not located in an area that is habitat for an endangered or threatened mammal under their jurisdiction, nor are any long-term adverse impacts to associated critical or unique habitats anticipated from BVPS operation.
- Based on their review of a BVPS license renewal activities summary, ODNR has determined that there will be no new and significant environmental implications in Ohio resulting from BVPS license renewal (Ref. 4.11-8); WVDNR indicated that they have no known occurrences of any rare, threatened, endangered, of special concern species in the vicinity of BVPS, nor do they have information indicating that WV wildlife resources have been affected by BVPS operations (Ref. 4.11-9).
- FWS indicates that, except for occasional transient species, no federally listed or proposed threatened or endangered species are known to occur within the project impact area (Attachment B).
- PA Game Commission office review conducted in response to preliminary impact assessments for these species (Attachment B) determined that, except for occasional transient individuals, BVPS license renewal should not affect endangered or threatened bird or mammal species recognized by that agency, nor would license renewal be expected to result in adverse impact to any critical or unique habitats.

Impact Conclusion: SMALL

Reptiles

Species and Status[a, b]

Eastern massasauga (*Sistrurus catenatus*), FC, PE

Timber rattlesnake (*Crotalus horridus*), PC

Occurrence Potential[a]

Eastern massasauga: None to Low. No recent confirmed occurrence in Beaver or Allegheny Counties. Little or no suitable wetland habitat on or near BVPS site or Beaver Valley-Crescent Line 318 transmission corridor.

Timber rattlesnake: Low on BVPS site. Low to Moderate on or near Beaver Valley-Crescent Line 318 transmission corridor, based on potential habitat availability.

Impact Initiators

No significant initiators.

TABLE 4.11-1 (CONTINUED)

SUMMARY IMPACT ASSESSMENT FOR THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL

Reptiles (continued)

Additional Impact Considerations and Conclusions[c]

- Neither species collected or observed in 1974-75 ecological surveys of BVPS site or site reconnaissance conducted in 2002.
- Results of PNDI searches and associated species impact reviews by PFBC (Ref. 4.11-2 through Ref. 4.11-7), conducted at FENOC's request, have not identified these species as potential conflicts with BVPS or transmission line operation.
- FENOC has not identified any significant land disturbing activities of natural habitats that would be undertaken for license renewal either on or in the vicinity of the BVPS site or along the Beaver Valley-Crescent Line 318 corridor.
- FWS indicates that, except for occasional transient species, no federally listed or proposed threatened or endangered species are known to occur within the project impact area (Attachment B)
- PFBC response to FENOC's preliminary impact assessment raised no concerns about BVPS license renewal with respect to these species (Attachment B).

Impact Conclusion: SMALL

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a. Tabulated species, status, and information related to occurrence potential based on information presented in Section 2.3 and Table 2.3-2.
b. Status Codes: FE = Federal Endangered, FT = Federal Threatened, FC = Federal Candidate for Listing, PE = Pennsylvania Endangered, PT = Pennsylvania Threatened, PC = Pennsylvania Candidate for Listing.
c. Additional considerations include controls established for impact initiators, industry and plant experience related to potential impacts, information received from regulatory agencies, and other relevant factors.

BVPS = Beaver Valley Power Station
EPA = U.S. Environmental Protection Agency
ER = Environmental Report
FENOC = FirstEnergy Nuclear Operating Company
FWS = U.S. Fish and Wildlife Service
NPDES = National Pollutant Discharge Elimination System
NRC = Nuclear Regulatory Commission
ODNR = Ohio Department of Natural Resources
PA = Commonwealth of Pennsylvania
PADEP = Pennsylvania Department of Environmental Protection
PDCNR = Pennsylvania Department of Conservation and Natural Resources
PNDI = Pennsylvania Natural Diversity Inventory
PFBC = Pennsylvania Fish and Boat Commission
USACE = U.S. Army Corps of Engineers
WVDNR = West Virginia Division of Natural Resources

4.12 AIR QUALITY DURING REFURBISHMENT (NONATTAINMENT AREAS)

NRC

"If the applicant's plant is located in or near a nonattainment or maintenance area, an assessment of vehicle exhaust emissions anticipated at the time of peak refurbishment workforce must be provided in accordance with the Clean Air Act as amended…." [10 CFR 51.53(c)(3)(ii)(F)]

"Air quality impacts from plant refurbishment associated with license renewal are expected to be small. However, vehicle exhaust emissions could be cause for concern at locations in or near nonattainment or maintenance areas. The significance of the potential impact cannot be determined without considering the compliance status of each site and the numbers of workers expected to be employed during the outage." (10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 50)

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

As discussed in Section 3.2 of this ER, FENOC does not plan to undertake major refurbishment for BVPS license renewal. FENOC concludes that there would be no refurbishment-related impacts to air quality, and no analysis is required.

4.13 IMPACT ON PUBLIC HEALTH OF MICROBIOLOGICAL ORGANISMS

NRC

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

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

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

The NRC, in its regulations at 10 CFR 51.53(c)(ii)(G), requires an assessment of the potential impact of thermophilic organisms in receiving waters on public health if a nuclear power plant uses cooling ponds, cooling lakes, or cooling canals, or discharges to a river with an average annual flow rate of less than 3.15×10^{12} cubic feet per year. Because the average Ohio River discharge in the vicinity of the BVPS site is approximately 1.25×10^{12} cubic feet per year (see Section 2.2), the NRC considers it to be a small river, making this issue applicable to BVPS-1 and BVPS-2. Organisms of concern include species of *Legionella* bacteria, the enteric pathogens *Salmonella* and *Shingella*, the *Pseudomonas aeruginosa* bacterium, thermophilic Actinomycetes species (fungi-like bacteria), and free-living pathogenic amoeba species. Of particular concern is the free-living pathogenic amoeba *Naegleria fowleri,* which is indigenous to soils (Ref. 4.1-1, Section 4.3.6).

Thermophilic bacteria generally occur at temperatures of 77 degrees Fahrenheit (°F) to 176°F, with maximum growth at 122°F to 140°F; bacteria pathogenic to humans typically have optimum temperatures of approximately 99°F (Ref. 4.13-1, page 60). Populations of the pathogenic amoeba *Naegleria fowleri* can be enhanced in thermally altered water bodies at temperatures ranging from 95°F to 106°F or higher, but this organism is rarely found in water cooler than 95°F based on studies reviewed by Tyndall et al. (Ref. 4.13-2).

As discussed in Section 2.3.1.1, the NRC reported in its BVPS-2 Operating License Stage Final Environmental Statement (FES) a maximum monthly average and daily maximum ambient temperatures of the Ohio River near the site to be 80°F and 86°F, respectively, which is in agreement with data for a more recent period of record (i.e., 1988-2002). A comparison of these temperatures with those considered optimal for growth as described above indicates that the ambient Ohio River would not support significant populations of thermophilic organisms. As a further possible indicator, the New Cumberland Pool of the Ohio River, where BVPS is located, is not listed by the Pennsylvania Department of Environmental Protection (PADEP) as being out of compliance with the Commonwealth's water quality standards with respect to pathogens or water quality parameters (e.g., organic enrichment, nutrients) that would tend to promote the growth of thermophilic organisms (see Section 2.3.1.1).

In the summer months when ambient river temperatures are warmest (June-August), BVPS site cooling water discharges from the uprated units to the Ohio River would consist of approximately 19 cubic feet per second (cfs) at a maximum temperature of 13°F above ambient river temperature at the emergency outfall structure and a maximum of approximately 95 cfs at 5°F to 10°F above ambient river temperature (as a maximum monthly average), primarily at the outfall structure (see Section 3.1.3.5). The resulting thermal plumes would be very small during this period, when the potential would be greatest for creating conditions warm enough for thermophilic organisms to proliferate. FENOC conservatively estimates that the plumes, defined by the 5°F isotherm, would encompass much less than 2 acres and extend downriver much less than 500-1,000 feet under extreme conditions (see Section 3.1.3.5). Corresponding maximum water temperatures at the 5°F isotherm would be approximately 85°F as a monthly average, and 91°F as a daily maximum. In addition, organisms inhabiting sediments on the river bottom or immersed banks that are exposed to the highest temperatures would be limited to those in the immediate discharge zone due to the mixing characteristics of the discharge and the tendency of warmest parts of the plume to remain near the water surface. Based on these considerations, FENOC believes that conditions in and near the cooling water discharge would not be suitable for the proliferation of thermophilic microbial pathogens such as *Naegleria fowleri*.

An additional factor for consideration is the potential for introduction of thermophilic pathogens in the BVPS site cooling water discharge itself, most of which is re-circulated in the plant cooling water systems. However, both the once-through cooling water discharged at the emergency outfall structure and the cooling tower blowdown are routinely treated with biocide, including hypochlorite (see Section 3.1.3.4). Some residual chlorine from biocide treatment, within limits prescribed in the National Pollution Discharge Elimination System (NPDES) permit, may be discharged. These biocide applications significantly reduce the likelihood that microbial inoculants would be discharged into the area of concern.

The limited potential for access by members of the public to waters and sediment in the immediate cooling water discharge areas is another factor relevant to this assessment. Access to the BVPS site by members of the public has always been subject to control, and shore-based recreation (e.g., fishing) on the property by the public is not permitted. In addition, the U.S. Coast Guard has established a security zone, effective indefinitely, that encompasses all waters extending 200 feet from the southeastern shoreline of the Ohio River, from river mile markers 34.6 to 35.1, including the entire frontage of the BVPS site. Entry of persons or vessels into this security zone is prohibited unless authorized by the Coast Guard Captain of the Port of Pittsburgh or his designated representative (see Section 2.1.3).

FENOC is not aware of any public health concerns or incidences related to the BVPS site cooling water discharge. In response to FENOC's general request to agencies for information as part of its new and significant information review, the Pennsylvania Department of Health indicated that it was not aware of any significant health issues that might affect the license renewal project (Ref. 4.13-3). In addition, FENOC has contacted the PADEP regarding this issue. Attachment B includes copies of the relevant correspondence with that agency. Most recently, in December, 2006, FENOC sent a letter to the PADEP inviting the PADEP to provide input into the license renewal environmental report review process, and specifically to identify to FENOC any concerns regarding license renewal or any information that could potentially be new and significant. The PADEP raised no issues or questions.

Based on the considerations presented above, FENOC concludes that impacts on public health from thermophilic microbiological organisms are not likely to occur as a result of license renewal, and there would be no impacts to mitigate. Because the definition of "small" includes impacts that are not detectable, the appropriate characterization of the impact on public health of microbiological organisms from continued operation of BVPS-1 and BVPS-2 in the license renewal period is SMALL, and further mitigation is unwarranted.

4.14 ELECTROMAGNETIC FIELDS – ACUTE EFFECTS

NRC

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

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

The NRC made the impact of electric shock from transmission lines a Category 2 issue because conformance of the plant's transmission lines with the currently applicable National Electrical Safety Code® (NESC®) standard for electric shock potential could not be determined without site-specific review (Ref. 4.1-1, Section 4.5.4.1). The NRC does not define the phrase "transmission line" in its regulations at 10 CFR 51.53(c)(3)(ii)(H), but does indicate in the GEIS that transmission lines use voltages of about 115/138 kilovolts (kV) and higher (Ref. 4.1-1, Section 4.5.1). As indicated in the regulation cited above, the transmission lines of concern to license renewal are those constructed for the specific purpose of connecting the plant to the transmission system. The NRC further elaborates in the GEIS and its guidance to applicants that the transmission lines to be addressed for license renewal are those that were constructed to connect the plant switchyard to the existing transmission system and reviewed as part of the construction permit for the plant (Ref. 4.1-1, Section 4.5; Ref. 4.1-2, Section 4.13).

As discussed in Section 3.1.4 of this environmental report, both FirstEnergy and Duquesne Light Company (Duquesne Light) consider the BVPS switchyard (Beaver Valley Substation) to be the transmission system interconnection for BVPS-1 and BVPS-2, and none of the transmission lines connecting at the switchyard were specifically constructed to connect the BVPS units to the transmission system. However, one new 15.8-mile 345-kilovolt (kV) transmission line connecting at the switchyard and reconfiguration of several spans exiting the switchyard that now comprise short segments of three other 345-kV lines were constructed in preparation for BVPS-2 operation to increase power system stability and reduce potential system overloads, and were addressed by the NRC in the BVPS-2 Operating License Stage FES. Therefore, FENOC has chosen to provide information and analyses for these transmission facilities in this environmental report (see Section 3.1.4). They consist of the following:

- Beaver Valley – Crescent Line (318) which extends 15.8 miles from the Beaver Valley Substation to Crescent Substation, owned and operated by Duquesne Light. For the initial 12-mile segment from the Beaver Valley Substation, the line shares double-circuit steel lattice towers with Duquesne Light's Beaver Valley-Clinton Line 314 (345 kV); for the 3.8-mile segment nearest the Crescent Substation, the line shares double-circuit single-pole steel structures with Duquesne Light's Collier-Crescent Line 331 (345 kV).

- Beaver Valley – Mansfield No. 1 (former Duquesne Light Line 316) from the Beaver Valley Substation to Tower 6278 (2 spans); owned and operated by American Transmission Systems, Inc. (ATSI), a FirstEnergy Corporation subsidiary.

- Beaver Valley – Mansfield No. 2 (former Duquesne Light Line 310) from the Beaver Valley Substation to Tower 6271 (2 spans); owned and operated by ATSI.

- Beaver Valley – Hanna (former Duquesne Light Line 320) from Tower 6270 near the Beaver Valley Substation to Tower 6602 (2 spans), where it meets Chamberlin-Mansfield Line 319 (345 kV); both lines are owned and operated by ATSI.

The Beaver Valley – Crescent line and the three reconfiguration segments addressed in this section are more fully described in Section 3.1.4 and are depicted in Figures 3.1-2 and 3.1-3. Section 3.1.4 also describes transmission facilities and corridor inspection and maintenance practices. Land use along the line is described in Section 2.3.2.

Information to be ascertained for the analysis with respect to these transmission facilities includes: (1) present conformance with the NESC® standard for electric shock hazard, (2) anticipated changes in transmission line operations or other parameters (e.g., land use) that would affect conformance with the NESC® standard, and (3) for any line segments for which nonconformance exists or is anticipated, a determination regarding the need for and nature of appropriate mitigation measures.

The NESC® standard applicable to this analysis (Ref. 4.14-1, Rule 232.C.1.c) specifies that electric lines operating at voltages exceeding 98 kV alternating current (AC) to ground must be designed with sufficient conductor clearance or other provisions as needed to limit the steady-state current[1] due to electrostatic effects to 5 milliamperes (mA) if the largest anticipated truck, vehicle, or other equipment under the line were short-circuited to ground. The rule further specifies that the determination of conductor clearance needed to meet the standard be performed under conditions of final unloaded conductor sag at 120°F.

Duquesne Light presented an analysis of the anticipated electrostatic effects of Beaver Valley Crescent line in the BVPS-2 Environmental Report – Operating License Stage (Ref. 4.11-11, Section 3.9.5) indicating that this line was designed in conformance with the NESC® 1981 standard. This earlier standard also specified an induced current standard of 5 mA. However, the analysis was conducted prior to construction, did not address the three additional short line segments listed above, and was addressed by the NRC in the corresponding FES (Ref. 4.14-2, Section 5.5.1.2) only in the context of ecological impacts. Therefore, FENOC conducted an independent analysis of each of these lines to determine conformance with the current NESC® standard.

The general procedure FENOC followed to determine induced current shock was to first calculate electric field strength under the lines using the Electric Power Research Institute

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

(EPRI) computer code, ENVIRO (Ref. 4.14-4). The results of this computer program have been field-verified through actual electric field measurements by several utilities. The input parameters included the design features of the transmission line. Next, FENOC calculated the induced current for the maximum vehicle size under the lines (a tractor-trailer), using methods prescribed in EPRI's Transmission Line Reference Book (Ref. 4.14-3).

For the three short reconfiguration segments (Mansfield #1, Mansfield #2, and Hanna), FENOC modeled actual road crossing locations near the plant, using measured clearances. Three such crossings were modeled. See Figure 3.1-2.

- The West Parking Lot (Figure 3.1-2) has the lowest clearance location for the Hanna line that is accessible to a large truck outside the security fence. The combined effect of the Hanna line and the Chamberlin-Mansfield line (not a BVPS line) were modeled since the two lines influence the selected location.
- The Mansfield #1, Mansfield #2, and Chamberlin-Mansfield lines cross PA Route 168, just east of the switchyard. The combined effect of these three lines were modeled.
- The Mansfield #1, Mansfield #2, and Chamberlin-Mansfield lines cross Greenhill Road (Road T451), just east of the PA Route 168 crossing. The combined effect of these three lines were modeled.

The Crescent line presented special challenges, since many of the profile drawings of the spans were not available. Therefore, for this much longer line, FENOC calculated a generic road crossing using the minimum design clearance. Duquesne Light's current design standard is to maintain a minimum 30-foot clearance for 345-kV lines. To ensure that this design standard exists in the as-built condition, FENOC performed field measurements of the Crescent line and found that all likely and accessible locations of low clearance were well in excess of 30 feet. (Minimum measured clearance was 43 feet.)

Table 4.14-1 provides the results of FENOC's induced current modeling. The results for the three short reconfiguration segments were so low compared to the 5 mA standard that only trucks parked perpendicular to the crossings were modeled. Except for the West Parking Lot, road crossings are perpendicular or nearly so. A parallel arrangement would be possible in the West Parking Lot, which would produce greater induced current. However, given, the low reported induced-current results, induced current for a parallel geometry would not be expected to approach 5 mA.

For the Crescent line, road crossings tend to be perpendicular, but less-than-perpendicular crossings exist. Completely parallel geometries would be difficult to envision. Nevertheless, because the reported induced current result is nearer to the standard and a generic crossing was modeled rather than specific ones, FENOC also calculated induced current for a parallel parking geometry. The result for the parallel geometry is 5 mA. Because of the much greater actual clearances and the unliklihood of a geometry approaching parallel, FENOC considers this to be a bounding condition not representative of reality. Accordingly, only the perpendicular results are reported in Table 4.14-1.

As discussed in Section 3.1.4, FirstEnergy (ATSI) and Duquesne Light perform periodic inspections and maintenance of the lines addressed in this analysis to determine the physical condition of towers, conductors, and other equipment; land use changes; and any encroachments on the corridors, which are either owned or appropriately controlled (e.g., through easements) by these companies. Appropriate practices in this regard would continue in the license renewal term, and neither FirstEnergy or Duquesne Light currently expect changes in operating voltage or other parameters for these lines that would affect conformance status with respect to the NESC® 5 mA standard.

On the basis of these considerations, FENOC concludes that the impact of electric shock is of SMALL significance for these transmission lines, and that further mitigation, such as the installation of warning signs at roadway crossings or increasing wire clearances, is not warranted.

As discussed in Section 3.1.4, FirstEnergy (ATSI) and Duquesne Light perform periodic inspections and maintenance of the lines addressed in this analysis to determine the physical condition of towers, conductors, and other equipment; land use changes; and any encroachments on the corridors, which are either owned or appropriately controlled (e.g., through easements) by these companies. Appropriate practices in this regard would continue in the license renewal term, and neither FirstEnergy or Duquesne Light currently expect changes in operating voltage or other parameters for these lines that would affect conformance status with respect to the NESC® 5 mA standard.

On the basis of these considerations, FENOC concludes that the impact of electric shock is of SMALL significance for these transmission lines, and that further mitigation, such as the installation of warning signs at roadway crossings or increasing wire clearances, is not warranted.

TABLE 4.14-1

CALCULATED INDUCED CURRENTS

Cross Section	Induced Current (mA)
Crescent	4.0
Hanna at West Parking Lot	1.7
Mansfield #1, Mansfield #2, Chamberlain-Mansfield at PA 168	0.8
Mansfield #1, Mansfield #2, Chamberlain-Mansfield at Green Hill Road	1.6

4.15 HOUSING IMPACTS

NRC

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

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

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

The NRC made housing impacts a Category 2 issue because impact magnitude depends on local conditions the NRC could not predict for all plants at the time of the GEIS publication (Ref. 4.1-1, Section 3.7.2). Local conditions that need to be ascertained are (1) population categorization as small, medium, or high and (2) applicability of growth control measures.

In 10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 63), the NRC concludes that impacts to housing are expected to be of small significance at plants in areas with a high population ranking where growth control measures are not in effect. Further, NRC states that impacts on housing would be considered to be of small significance when a small and not easily discernible change in housing availability occurs, generally as a result of a very small demand increase or a very large housing market.

4.15.1 Refurbishment

As discussed in Section 3.2 of this ER, FENOC does not plan to undertake major refurbishment for BVPS license renewal. FENOC concludes that there would be no refurbishment-related impacts to housing, and no analysis is required.

4.15.2 License Renewal Term

The maximum impact to area housing was assessed using the following assumptions: (1) FENOC would add an additional 60 permanent employees to the BVPS workforce for the duration of the license renewal term and that the 60 direct jobs at BVPS would result in 195 indirect jobs, (2) each direct and indirect job is filled by an in-migrating worker and workers would distribute themselves as the current employees do with 82 percent settling in Beaver or Allegheny Counties, and (3) each new job would represent one housing unit.

License renewal activities could bring as many as 255 new workers to the region, generating demand for 255 housing units during the license renewal term. As discussed in Section 2.5 and 2.9, the BVPS site is located in a high population area, and both Beaver and Allegheny Counties encourage development in areas that can be served by existing infrastructure. License renewal activities could increase the demand for housing, but the increase would be small and the housing market is very large. Therefore, FENOC expects housing impacts during the license renewal term to be SMALL and mitigative measures would not be necessary.

4.16 PUBLIC UTILITIES: PUBLIC WATER SUPPLY AVAILABILITY

NRC

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

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

"Impacts on public utility services are considered small if little or no change occurs in the ability to respond to the level of demand and thus there is no need to add capital facilities. Impacts are considered moderate if overtaxing of facilities during peak demand periods occurs. Impacts are considered large if existing service levels (such as quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services." (Ref. 4.1-1, Section 3.7.4.5)

NRC made public utility impacts a Category 2 issue because an increased problem with water availability, resulting from pre-existing water shortages, could occur in conjunction with plant demand and plant-related population growth (Ref. 4.1-1). Local information needed would include: (1) a description of water shortages experienced in the area, and (2) an assessment of the public water supply system's available capacity. NRC's analysis of impacts to the public water supply system considered both plant demand and plant-related population growth demands on public water systems.

As FENOC notes in Section 3.1.3, BVPS acquires potable water from the Midland Water Authority. Current average daily plant usage represents 1.5 percent of the Midland Water Authority's average daily demand and 0.9 percent of its permitted capacity. Midland Valley Water Authority has an excess capacity of 2.1 MGD (Section 2.8.1; Section 3.1.3.6).

4.16.1 Refurbishment

As discussed in Section 3.2 of this ER, FENOC does not plan to undertake major refurbishment for BVPS license renewal. FENOC concludes that there would be no refurbishment-related impacts to public utilities, and no analysis is required.

4.16.2 License Renewal Term

Section 2.8.1 describes the public water supply systems in Allegheny and Beaver Counties. The following discussion focuses on impacts of continued operations on local public utilities using the assumptions that (1) FENOC would add an additional 60 permanent employees to the BVPS workforce for the duration of the license renewal term and that the 60 direct jobs at BVPS would result in 195 indirect jobs, (2) each direct and indirect job is filled by an in-migrating worker, and (3) new workers would distribute themselves as the current employees do with 82 percent settling in Beaver or Allegheny Counties.

The average number of people in a Pennsylvania household is 2.48 (Ref. 3.4-2). An additional 255 employees could result in a population increase of approximately 632 people (255 x 2.48 = 632.4) in Allegheny and Beaver Counties. The average American uses between 50 and 80 gallons per day for personal use (Ref. 4.16-2, page 2). Using a consumption rate of

80 gallons per person, this population increase could require an approximate additional 50,560 gallons per day. The combined water systems in both counties have a total excess capacity of approximately 81 MGD. Therefore, FENOC concludes that impacts to local water supplies resulting from 60 additional permanent employees at BVPS would be SMALL and would not require mitigation.

4.17 EDUCATION IMPACTS FROM REFURBISHMENT

NRC
The environmental report must contain "An assessment of the impact of the proposed action on... public schools (impacts from refurbishment activities only) within the vicinity of the plant...." [10 CFR 51.53(c)(3)(ii)(I)]
"...Most sites would experience impacts of small significance but larger impacts are possible depending on site- and project-specific factors...." (10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 66)
"...small impacts are associated with project-related enrollment increases of 3 percent or less. Impacts are considered small if there is no change in the school systems' abilities to provide educational services and if no additional teaching staff or classroom space is needed. Moderate impacts are associated with 4 to 8 percent increases in enrollment, and if a school system must increase its teaching staff or classroom space even slightly to preserve its pre-project level of service.... Large impacts are associated with enrollment increases greater than 8 percent...." (Ref. 4.1-1, Section 3.7.4.1)

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

As discussed in Section 3.2 of this ER, FENOC does not plan to undertake major refurbishment for BVPS license renewal. FENOC concludes that there would be no refurbishment-related impacts to education, and no analysis is required.

4.18 OFFSITE LAND USE

4.18.1 Refurbishment

NRC

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

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

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

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

As discussed in Section 3.2 of this ER, FENOC does not plan to undertake major refurbishment for BVPS license renewal. FENOC concludes that there would be no refurbishment-related impacts to off-site land use, and no analysis is required.

4.18.2 Offsite Land Use: License Renewal Term

NRC

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

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

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

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

The NRC made impacts to offsite land use during the license renewal term a Category 2 issue because land use changes may be perceived to be beneficial by some community members and adverse by others. Therefore, the NRC could not assess the potential significance of site-specific offsite land-use impacts (Ref. 4.1-1, Section 4.7.4. 2).

In the GEIS, the NRC presents an analysis of population-driven and tax-driven impacts on offsite land use for the renewal term (Ref. 4.1-1, Section 4.7.4.1). Based on the case study analysis described in the GEIS, the NRC concludes that all new population-driven land-use changes during the license renewal term at all nuclear power plants would be small because population growth caused by license renewal would represent a much smaller percentage of the local area's total population than has resulted from plant operation (Ref. 4.1-1, Section 4.7.4.2).

Section 4.7.4.1 of the GEIS (Ref. 4.1-1) states that the assessment of tax-driven land-use impacts during the license renewal term should consider (1) the size of the plant's payments relative to the community's total revenues, (2) the nature of the community's existing land-use pattern, and (3) the extent to which the community already has public services in place to support and guide development. If the plant's tax payments are projected to be small relative to the community's total revenue, new tax-driven land-use changes by the plant during the plant's license renewal term would be SMALL, especially where the community has pre-established patterns of development and has provided adequate public services to support and guide development. If the plant's tax payments are projected to be medium-to-large relative to the community's total revenue, new tax-driven land-use changes will be MODERATE. This is most likely to be true where the community has no pre-established patterns of development (i.e., land-use plans or controls) or has not provided adequate public services to support and guide development in the past, especially infrastructure that would allow industrial development. If the plant's tax payments are projected to be a dominant source of the community's total revenue, new tax-driven land-use changes would be LARGE. This would be especially true where the community has no pre-established pattern of development or has not provided adequate public services to support and guide development in the past.

FENOC 's annual property tax payments to Beaver County for the BVPS site represent less than 1 percent of the county's annual operating budget for the period 2001 through 2005 (Table 2.7-1). During the same period, FENOC's property tax payments to Shippingport Borough for the BVPS site represented an average of approximately 4.8 percent of the Borough's' annual operating budget. This number is inflated due to a one-year tax increase (in 2002) that was used to fund the completion of a sewer project, which then returned to historical values. FENOC 's annual property tax payments to the South Side Area School District of Beaver County for the BVPS site represent an average of approximately 8.6 percent of the School District's annual operating budget, but has exhibited a downward trend, decreasing from 15.9 percent in 2001 to 0.07 percent in 2005. As noted in Section 2.7, FENOC assumes that these values are substantially representative of conditions that would exist in the BVPS license renewal term.

The NRC has determined that the significance of tax payments is small if payments are less than 10 percent of a taxing jurisdiction's total revenue, moderate if payments are 10 to 20 percent, and large if payments are greater than 20 percent (Ref. 4.1-1, Section 4.7.2.1). On the basis of these criteria, FENOC's payments to the county, borough, and school district are small relative to their operating budgets.

As noted in the introduction to this section, the potential for tax-driven impacts relates not only to those relative budget contributions, but also on existing land use patterns and controls. Beaver County has not experienced any significant changes in land-use patterns due to the operation of BVPS-1 and BVPS-2. Current land use characteristics within Beaver County, as described in Section 2.9, are similar to those described in the Final Environmental Statements for both BVPS units (Ref. 4.18-1; Ref. 4.14-2). As described in Section 2.9, development is encouraged in areas that can be served by existing infrastructure. Much of the existing development is located in older river communities that are declining in economic activity. Continued growth is expected in the northern and eastern undeveloped portions of Beaver County, while western Beaver County is expected to remain largely rural. Overall, total population within Beaver County has declined in the past 20 years. From 1980 to 2000, total population in Beaver County has decreased by nearly 9 percent, and the Pennsylvania State Data Center projects that populations in the county will continue to decrease by less than one percent annually, through the year 2020 (see Section 2.5).

As noted in Section 2.1, development of open land in the Shippingport Borough and other river communities surrounding the BVPS site is hindered by existing development and local topography. As described in Section 2.9, an established pattern of development exists in Beaver County and Shippingport Borough. Both Beaver County and many of its municipalities have developed comprehensive planning documents. The Beaver County Planning Commission supports the goal of guiding development in areas that can be served by existing infrastructure. Municipalities within Beaver County, including Shippingport Borough, administer land use regulations, such as zoning, designed to regulate and guide development.

Given the plant's small contribution to the Beaver County operating budget and declining populations and established pattern of growth that exists in Beaver County, including Shippingport Borough, FENOC expects few, if any, land use changes during the renewal period due to new tax-driven impacts. In addition, continued tax payments attributable to BVPS license renewal (i.e., during period of extended operation) could act to moderate adverse impacts on land use, if any, that may result from projected population decline and associated erosion of residential tax base. FENOC concludes that tax-driven land-use impacts would be SMALL and additional mitigation would not be warranted.

4.19 TRANSPORTATION

NRC

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

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

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

The NRC made impacts to transportation a Category 2 issue because road conditions existing at the time of the project, which the NRC could not forecast for all plants (Ref. 4.1-1, Section 3.7.4.2), primarily determines impact significance. Local road conditions to be ascertained are (1) highway capacity and traffic flow and (2) incremental increase in traffic associated with major refurbishment activities and additional permanent employees attributable to license renewal.

4.19.1 Refurbishment

As discussed in Section 3.2 of this ER, FENOC does not plan to undertake major refurbishment for BVPS license renewal. FENOC concludes that there would be no refurbishment-related impacts to transportation, and no analysis is required.

4.19.2 License Renewal Term

As FENOC notes in Section 2.8.2, access to the BVPS site is via State Route (SR) 168, and the major commuting routes used by BVPS site employees are in rural and uncongested areas. The current BVPS workforce is approximately 1,500 employees, including FENOC employees and contractors (Section 3.4). Refueling outages, which are scheduled approximately every 18 months and last about 30 days, add as many as 800 temporary workers. FENOC's conservative assumption of 60 additional employees associated with operating through the license renewal terms for BVPS-1 and BVPS-2 represents a very small (approximately 4 percent) increase in the current number of employees and an even smaller percentage of the employees on-site during outages (e.g., for periodic refueling), when BVPS traffic volume is heaviest. Historically, increased traffic during outages has not challanged the capacity of local roads.

FENOC routinely employs personnel to direct traffic during high volume periods, including morning and afternoon shift changes during normal operation, which ensures efficient traffic flow on SR 168 at the site. The Council for the Borough of Shippingport has stated that they do not anticipate the need to increase the number of roads or traffic lanes for the Unit 2 SGRP (Ref. 4.19-1). In addition, the Beaver County Planning Department has not identified any of the major commuting routes to BVPS as deficient due to limited capacity or physical condition (see

Section 2.8). Finally, as described in Section 2.5, BVPS is located in an area of declining population; therefore, traffic volumes are not expected to increase. On the basis of these considerations and the traffic counts and classifications for SR 168 and commuting routes to the BVPS site as described in Section 2.8.2 and Table 2.8-1, FENOC concludes that impacts to transportation from continued operation of BVPS-1 and BVPS-2 in the license renewal period would be SMALL and mitigative measures would not be necessary.

4.20 HISTORIC AND ARCHAEOLOGICAL RESOURCES

NRC

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

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

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

The NRC made impacts to historic and archaeological resources a Category 2 issue because determinations of impacts to historic and archaeological resources are site-specific in nature, and the National Historic Preservation Act mandates that determination of impacts must be made through consultation with the State Historic Preservation Officer (SHPO) (Ref. 4.1-1, Section 4.7.7.3).

4.20.1 Refurbishment

As discussed in Section 3.2 of this ER, FENOC does not plan to undertake major refurbishment for BVPS license renewal. FENOC concludes that there would be no refurbishment-related impacts to historic and archaeological resources, and no analysis is required.

4.20.2 License Renewal Term

FENOC is not aware of any historic or archaeological resources that have been affected to date by BVPS operations, including operation and maintenance of transmission lines. FENOC is aware, however, that the site vicinity and the surrounding environs have potential for containing cultural resources. Additionally, FENOC is aware of cultural resources that are within or near BVPS boundaries. Because FENOC is aware of the potential for the discovery of cultural resources during land-disturbing activities at its facilities and along its transmission line corridors, it has included protection of those resources in its "Environmental Evaluations" procedure. FENOC also intends to formalize a ground disturbance/excavation control program for purposes of implementing artifact discovery/protection practices. Because FENOC has no plans to construct new license renewal related facilities at BVPS during the license renewal term and because the policies and procedures established in the "Environmental Evaluations" procedure should protect any resources that have been previously identified or inadvertently discovered, FENOC concludes that operation of generation and transmission facilities over the license renewal term would not impact cultural resources; hence, no mitigation measures would be warranted beyond those prescribed in FENOC's "Environmental Evaluations" procedure.

As discussed in Section 2.10, FENOC reviewed the FES' for BVPS-1 and BVPS-2 and listings of the National Park Service (NPS) and the Pennsylvania Historical and Museum Commission, Bureau for Historic Preservation (PBHP) for National Register of Historic Places listed and eligible properties. In addition, FENOC has consulted directly with PBHP (the Pennsylvania SHPO) regarding the potential impact of continued operation of BVPS and transmission lines addressed in this environmental report as part of its license renewal environmental review. Results of these activities indicate that there are no National Register eligible or listed historic or archaeological properties on or near the BVPS site or the transmission line corridors (see Section 2.10 and Attachment B). In December, 2006, FENOC sent a letter to the PBHP inviting the PBHP to provide input into the license renewal environmental report review process, and specifically to identify to FENOC any concerns regarding license renewal or any information that could potentially be new and significant. The PBHP raised no issues or questions.

In view of these considerations, operation of BVPS and transmission lines addressed in this environmental report in the license renewal term would have no effect on significant historic and archaeological resources. FENOC therefore concludes that impacts on historic and archaeological resources associated with license renewal would be SMALL, and mitigation would be unwarranted.

4.21 SEVERE ACCIDENT MITIGATION ALTERNATIVES ANALYSIS

NRC

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

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

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

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

The NRC concluded in its generic license renewal rulemaking that the unmitigated environmental impacts from severe accidents met the Category 1 criteria, but the NRC made consideration of mitigation alternatives a Category 2 issue because ongoing regulatory programs related to mitigation [i.e., Individual Plant Examination (IPE) and Accident Management] have not been completed for all plants. Since these programs have identified plant programmatic and procedural improvements (and, in a few cases, minor modifications) as cost effective in reducing severe accident and risk consequences, the NRC thought it premature to draw a generic conclusion as to whether severe accident mitigation would be required for license renewal.

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

4.21.1 Methodology Overview

FENOC performed unit-specific SAMA analyses for both of the BVPS Units. Even though these units went into operation 11 years apart, their designs are virtually the same and there is little to differentiate them relative to the SAMAs that have been analyzed. Where there are differences relative to the SAMA analyses, these have been identified in the detailed SAMA discussions in Attachment C of this ER. The methodology for performing the SAMA analyses was identical for each Unit and is summarized in the following paragraphs.

The methodology used to perform the BVPS SAMA analysis is contained in the "Severe Accident Mitigation Alternatives (SAMA) Analysis Guidance Document," NEI 05-01 Rev. A (Ref. 4.21-1) which implements the handbook used by the NRC to analyze benefits and costs of its regulatory activities, "Regulatory Analysis Technical Evaluation Handbook," NUREG/BR-0184, January 1997 (Ref. 4.21-2), subject to Beaver Valley Unit 1 and Unit 2-specific considerations.

Environmental impact statements and environmental reports are prepared using the graded approach in which impacts of greater concern and mitigation measures of greater potential value are studied with correspondingly greater effort and rigor. Accordingly, FENOC used screening methods and less detailed feasibility investigative and cost estimation techniques for SAMA candidates having disproportionately high costs or low benefits. The more detailed evaluations were applied to the most viable candidates.

Initial inputs for the BVPS SAMA benefits analyses were the Beaver Valley Unit 1 and Unit 2 probabilistic risk assessment (PRA) models (Refs. 4.21-3 and 4.21-4). These models are updated versions of the Individual Plant Examination; the Unit 1 model (Ref. 4.21-5) was updated as of June 2006 and the Unit 2 model (Ref 4.21-6) was updated as of April 2007.

The outline of the approach taken in the BVPS SAMA analysis is:

- NUREG/BR-0184 was used to assign unmitigated (base case) severe accident impacts (see Table 4.21-1) as follows:

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

      The BVPS PRA models specified total accident frequency (core damage frequency (CDF) and containment release frequency); Melcor Accident Consequences Code System (MACCS2) (Ref. 4.21-7)specified public dose; and NUREG/BR-0184 conversions of dose to present worth dollars (based on valuation of $2,000 per person-rem and a present worth discount factor of 7%).

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

      The BVPS PRA models specified total accident frequency; MACCS2 specified offsite property damage; and NUREG/BR-0184 conversions of offsite property damage to present worth dollars.

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

The BVPS PRA models specified total core damage frequency, NUREG/BR-0184 best estimate occupational dose values for immediate and long-term dose, NUREG/BR-0184 conversions of dose to present worth dollars (based on valuation of $2,000 per person-rem and a present worth discount factor of 7%).

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

  The BVPS PRA models specified core damage frequency, NUREG/BR-0184 best estimate cleanup and decontamination costs, and NUREG/BR-0184 conversions of onsite property damage to present worth dollars. It is conservatively assumed that, subsequent to a severe accident, the plant would not be restored to operation; therefore, replacement/refurbishment costs are not included in onsite costs. Replacement power costs are included in this analysis.

- SAMA Identification – Potential SAMAs were identified from the following sources:

  - Potential plant improvements from the NRC and industry (contained in NEI 05-01); and

  - Insights provided by BVPS staff familiar with the BVPS IPE, IPEEE, and current PRA model.

- Preliminary Screening – Non-viable candidates were identified then eliminated from further consideration based upon:

  - Non-applicability to the Beaver Valley unit;

  - Having been implemented at the Beaver Valley unit (or benefits have been achieved using other means),

  - Having been combined with a similar SAMA for later evaluation in the cost/benefit (Phase II) analysis,

  - Excessive cost, or

  - Low benefit.

- Final Screening of Remaining SAMAs – Using cost-benefit analysis techniques, alternatives were eliminated from further consideration if their individual implementation cost exceeded its benefit (derived as follows):

  - Benefit calculation – The benefits of implementing each SAMA individually was evaluated;

- SAMA impacts – Calculate impacts (i.e., on-site/off-site dose and damages) by configuring the BVPS PRA models to the revised plant configuration (and risk trees) simulating implementation of the SAMA being evaluated.

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

- Cost estimate – The cost of implementing each evaluated SAMA was estimated using the graded approach discussed above. The cost estimation was performed by an expert panel of senior BVPS staff members with experience in design, operation, maintenance, training and licensing.

- Sensitivity Analysis – Several calculations were made to determine how changes in the SAMA analysis assumptions and uncertainties could affect the SAMA screening process or its outcomes.

- Conclusions – Several SAMAs were identified at each unit that are potentially cost beneficial and they will be considered further by FENOC. Tables 4.21-2 and 4.21-3 list the potentially cost beneficial SAMAs for BVPS Unit 1 and Unit 2, respectively.

FENOC's SAMA analyses for BVPS Units 1 and 2 are presented in the following sections.

4.21.2 Establishing the Base Case

The purpose of establishing the base case is to provide the baseline for determining the risk reductions that would be attributable to the implementation of potential SAMAs. This severe accident risk, based on the Beaver Valley unit-specific PRA model, is calculated through use of the Level 2 and the MACCS2 Level 3 model, based upon site-specific meteorology, population characteristics, and economic information.

The primary source of data relating to the base case is the Beaver Valley Unit 1 or 2 PRA model. These models are based upon the latest modeling information available for the respective unit, and use PRA techniques to:

- Develop an understanding of severe accident behavior;

- Understand the most likely severe accident consequences;

- Gain a quantitative understanding of the overall probabilities of core damage and fission product releases; and

- Evaluate hardware and procedure changes to assess the overall changes in probabilities of core damage and fission product releases.

The Beaver Valley Unit 1 and 2 PRA models include both internal events (e.g., loss of feedwater event, loss of coolant accident) and external events (seismic events, fire events). The Beaver Valley PRA models are periodically updated as a result of:

- Equipment Performance – As data collection progresses, estimated failure rates and system unavailabilities change.

- Plant Configuration Changes (as of the stated "freeze date") – There is a time lag between changes to the plant and incorporation of those changes into the Beaver Valley PRA models.

- Modeling Changes – The Beaver Valley PRA models are refined to incorporate the latest state of knowledge.

The Beaver Valley PRA models describe the results of the first two levels of the PRA for the respective Beaver Valley unit. These levels are defined as follows: Level 1 – determines core damage frequencies based on system analyses and human-factor evaluations; and Level 2 – determines the physical and chemical phenomena that affect the performance of the containment and other radiological release mitigation features to quantify accident behavior and potential release of fission products to the environment. The MAAP-DBA code was used to generate dose-related input to this SAMA analysis; plant specific radionuclide release fractions were, therefore, used in the MACCS2 analyses.

Using the results of these analyses, the next step is to perform a Level 3 PRA analysis, which calculates the hypothetical impacts of severe accidents on the surrounding environment and members of the public. Based on the similarity of the Level 2 PRA models at Units 1 and 2, a bounding approach was used to define a common Level 3 model which is applicable to both units. MACCS2 is the code used for determining the offsite impacts for the Level 3 analysis. The Level 3 model is used to estimate offsite impacts for each plant. The magnitude of the onsite impacts (in terms of clean up and decontamination costs and occupational dose) are based on information provided in NUREG/BR-0184. The principal phenomena analyzed are atmospheric transport of radionuclides, mitigation actions (i.e., evacuation, condemnation of contaminated crops and milk) based on dose projection, dose accumulation by a number of pathways, including food and water ingestion, and economic costs. Input for the Level 3 analysis includes a composite Beaver Valley Unit 1 and Unit 2 core radionuclide inventory, Beaver Valley unit source terms, site meteorological data, projected population distribution (within 50-mile radius) for the year 2047, emergency response evacuation modeling, and economic data.

The Level 3 analysis evaluates the consequence of the released source term for each of the release modes associated with endstates of the containment event tree. Because the analysis is based on probabilistic risk input, the analytical results relate the frequency of an impact to the magnitude of the impact (i.e., frequency versus consequences). In general, severe accidents having the greater predicted impact have the lower predicted probability of occurrence.

Attachment C-1 contains detailed information on the SAMAs for Unit 1 and Attachment C-2 contains detailed information on the SAMAs for Unit 2; each report is organized consistent with the SAMA guidance document, NEI 05-01.

Offsite Exposure Costs

The Level 3 base case analysis results in an annual offsite exposure risk of 57.9 person-rem for Unit 1 and 55.9 person-rem for Unit 2. This calculated value is converted to a monetary equivalent (dollars) via application of the NRC's conversion factor of $2,000 per person-rem from NUREG/BR-0184. This monetary equivalent was then discounted to present value using the formula from NUREG/BR-0184:

$$APE = \left(F_S D_{P_S} - F_A D_{P_A}\right) R \frac{1 - e^{-rt_f}}{r} \qquad (1)$$

where:

APE = Averted Public Exposure - monetary value of accident risk avoided due to population doses, after discounting

R	=	monetary equivalent of unit dose, ($2,000/person-rem)
F	=	accident frequency (events/yr)
DP	=	population dose factor (person-rems/event)
S	=	status quo (current conditions)
A	=	after implementation of proposed action
r	=	real discount rate = 7% (as a fraction, 0.07)
tf	=	analysis period (years) = 20 years.

Using a 20-year period for extended plant life and a 7% discount rate results in the monetary equivalent value presented in Table 4.21-1.

Offsite Economic Costs

The Level 3 analysis shows an annual offsite economic risk monetary equivalent of $322,875 at Unit 1 or $315,772 at Unit 2. Calculated values of offsite economic costs caused by severe accidents must also be discounted to present value. Discounting is performed in the same manner as for the public health risks in accordance with the following equation:

$$AOC = \left(F_S P_{D_S} - F_A P_{D_A}\right) \frac{1 - e^{-rt_f}}{r}$$

where:

AOC = Averted Offsite Costs - monetary value of accident risk avoided due to offsite property damage, after discounting

PD = offsite property loss factor (dollars/event)

The resulting monetary equivalent is presented in Table 4.21-1.

Onsite Exposure Cost

Values for occupation exposure associated with severe accidents are not derived from the Beaver Valley PRA models, but, instead, are obtained from information published by the NRC in NUREG/BR-0184. The values for occupational exposure consist of "immediate dose" and "long-term dose." The best estimate value provided by the NRC for immediate occupational dose due to a hypothetical severe accident is 3,300 person-rem, and long-term occupational dose is 20,000 person-rem (over a ten-year clean-up period). The following equations are applied to these values to calculate monetary equivalents:

Immediate Dose

For a currently operating facility, NUREG/BR-0184 calculates the immediate dose present value using the following equation:

Equation (1):

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

where:

WIO = monetary value of accident risk avoided due to immediate doses, after discounting

IO = subscript denoting immediate occupational dose

R = monetary equivalent of unit dose, ($/person-rem)

F = accident frequency (events/yr)

DIO = immediate occupational dose (person-rems/event)

S = status quo (current conditions)

A = after implementation of proposed action

r = real discount rate

tf = analysis period (years).

The values used in the Beaver Valley analysis are:

R = \$2,000/person-rem

r = 0.07

DIO = 3,300 person-rems /accident (best estimate)

tf = analysis period (years) = 20years.

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

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

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

For the core damage frequency for the base case at Unit 1, 1.94E-05/year,

$$W_{IO} = \$1381$$

For the core damage frequency for the base case at Unit 2, 2.40E-05/year,

$$W_{IO} = \$1707$$

Long-Term Dose

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

Equation (2):

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

where:

WLTO = monetary value of accident risk avoided long term doses, after discounting, (\$)

LTO = subscript denoting long-term occupational dose

m = years over which long-term doses accrue

The values used in the Beaver Valley Unit 1 and Unit 2 analyses are:

R = $2,000/person-rem

r = .07

DLTO = 20,000 person-rem /accident (best estimate)

m = "as long as 10 years"

tf = analysis period (years) = 20years.

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

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

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

For the core damage frequency for the base case at Unit 1, 1.94E-05/year,

$$W_{LTO} = \$6020$$

For the core damage frequency for the base case at Unit 2, 2.40E-05/year,

$$W_{LTO} = \$7,439$$

Total Occupational Exposures

Combining equations (1) and (2) above, using delta (Δ) to signify the difference in accident frequency resulting from the proposed actions, and using the above numerical values, the long term accident related onsite Averted Occupational Exposure (AOE) is:

$$AOE = \Delta W_{IO} + \Delta W_{LTO} \ (\$)$$

The bounding value for occupational exposure (AOEB) is:

$$AOE_B = W_{IO} + W_{LTO}$$

The resulting monetary equivalent is presented in Table 4.21-1.

Onsite Economic Costs

Clean-up/Decontamination

The total cost of clean-up/decontamination of a power reactor facility subsequent to a severe accident is estimated in NUREG/BR-0184 at $1.5E+9; this same value was adopted for these analyses. Considering a 10-year cleanup period, the present value of this cost is:

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

where:

PVCD =		present value of the cost of cleanup/decontamination
CD	=	subscript denoting clean-up/decontamination
CCD	=	total cost of the cleanup/decontamination effort, $1.5E+9
m	=	cleanup period (10 years)
r	=	discount rate (7%).

Therefore:

$$PV_{CD} = \left(\frac{\$1.5E+9}{10}\right)\left(\frac{1-e^{-.07*10}}{.07}\right)$$

Where:

PV_{CD} = present value of the cost of clean-up/decontamination

$$PV_{CD} = \$1.079E+9$$

This cost is integrated over the term of the proposed license extension as follows:

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

Where:

U_{CD} = total cost of clean-up/decontamination over the life of the plant

Based upon the values previously assumed:

$$U_{CD} = \$1.161E+10$$

Replacement Power Costs

The analysis was performed including consideration of replacement power costs, modeled in accordance with the guidance provided in NUREG/BR-0184.

The present value of replacement power is calculated as follows:

$$PV_{RP} = \left(\frac{(\$1.2E+8)\dfrac{(Ratepwr)}{(910MWe)}}{r} \right) \left(1 - e^{-rt_f}\right)^2$$

Where:

PV_{RP}	=	Present value of the cost of replacement power for a single event.
t_f	=	analysis period (years) = 20years.
r	=	Discount rate (7%).
Ratepwr	=	Rated power of each unit (984 MWe for Unit 1; 977 MWe for Unit 2).

The $1.2E+8 value has no intrinsic meaning but is a substitute for a string of non-constant replacement power costs that occur over the lifetime of a "generic" reactor after an event (from Reference 20). This equation was developed per NUREG/BR-0184 for discount rates between 5% and 10% only.

For discount rates between 1% and 5%, NUREG/BR-0184 indicates that a linear interpolation is appropriate between present values of $1.2E+9 at 5% and $1.6E+9 at 1%. So for discount rates in this range the following equation was used to perform this linear interpolation.

$$PV_{RP} = \left\{ (\$1.6E+9) - \left(\frac{[(\$1.6E+9) - (\$1.2E+9)]}{[5\% - 1\%]} * [r_s - 1\%] \right) \right\} * \left\{ \frac{Ratepwr}{910MWe} \right\}$$

where:

rs	=	Discount rate (small), between 1% and 5%.
Ratepwr	=	Rated power of each unit

To account for the entire lifetime of the facility, URP was then calculated from PVRP, as follows:

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

where:

U_{RP} = Present value of the cost of replacement power over the life of the facility.

Again, this equation is only applicable in the range of discount rates from 5% to 10%. NUREG/BR-0184 states that for lower discount rates, linear interpolations for URP are recommended between $1.9E+10 at 1% and $1.2E+10 at 5%. The following equation was used to perform this linear interpolation:

$$U_{RP} = \left\{ (\$1.9E+10) - \left(\frac{[(\$1.9E+10) - (\$1.2E+10)]}{[5\% - 1\%]} * [r_s - 1\%] \right) \right\} * \left\{ \frac{Ratepwr}{910MWe} \right\}$$

where:

r_s = Discount rate (small), between 1% and 5%.

Ratepwr = Rated power of each unit

For the base case, URP = $8.5E+9 for each unit.

Repair and Refurbishment

It is assumed that the plant would not be repaired.

Total Onsite Property Damage Costs

The total averted onsite costs (AOSC) of the damage is, therefore:

$$AOSC = F * (U_{CD} + U_{RP})$$

where:

F = Annual frequency of the event.

The resulting monetary equivalent for Units 1 and 2 is presented in Table 4.21-1.

4.21.3 SAMA Identification and Screening

The NRC and the nuclear industry have documented methods to mitigate severe accident impacts for existing and new plants designs and for in-system evaluations and has captured them in the guidance used for performing SAMA analyses (NEI 05-01), which lists documents from which NEI gathered descriptions of candidate SAMAs. In addition, FENOC, in preparing the BVPS Unit 1 and Unit 2 IPEs, IPEEEs (Refs. 4.21-8 and 4.21-9), and current PRA models, gained insight into possible improvements that could reduce severe accident risks. These insights were used to identify plant specific SAMAs. Table 5.6-1 of Attachment C-1 and of Attachment C-2 lists the candidate SAMAs for the respective units that FENOC identified for analysis and identifies the source of the information. There were 189 candidates identified for Unit 1 and 190 candidates identified for Unit 2. The first step in the analysis was to eliminate non-viable SAMAs through preliminary screening.

Preliminary Screening

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

- Enhancements not applicable to the unit (e.g., applicable only to boiling water reactors);
- Enhancements that have already been implemented at the unit (e.g., procedure changes and plant modifications that meet the intent of the SAMA);
- For enhancements that were similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or plant-specific SAMA candidate, only the combined SAMA candidate was retained;
- Enhancements that involve extensive changes that will obviously exceed the maximum benefit; and
- Enhancements from an industry document that related to a non-risk significant system for which change in reliability is known to have negligible impact on the risk profile (Note that no SAMAs were screened using this criterion).

Table 6-1 of Attachment C-1 and of Attachment C-2 lists the candidate SAMAs for the respective units and provides a brief discussion of each candidate SAMA and its disposition, whether eliminated from further consideration as not applicable, as already implemented (or the intent met), or designated for further analysis. Based on this preliminary screening, 126 candidate SAMAs were eliminated from the Unit 1 list, and 63 of the original Unit 1 SAMAs were designated for further analysis. For Unit 2, 134 candidates were eliminated in this screening and 56 were designated for further analysis.

Final Screening/Cost-Benefit Analysis

FENOC estimated the costs of implementing each SAMA through the application of engineering judgment, estimates from other licensee's submittals, and site-specific cost estimates. Evaluation was performed based on a single nuclear unit implementation basis. The cost estimates did not include the cost of replacement power during extended outages required to implement the modifications, nor did they include contingency costs associated with unforeseen implementation obstacles. Estimates based on modifications that were implemented or estimated in the past were presented in terms of dollar values at the time of implementation (or estimation), and were not adjusted to present-day dollars. Therefore, the cost estimates were conservatively low.

Screening based on level of benefit achieved was carried out in two steps. The first step involved calculating the maximum benefit that could possibly be provided by any one SAMA or combination of SAMAs. This maximum theoretical benefit is based upon the elimination of all plant risk and equates to the previously calculated base case risk. The monetized value of the maximum avoided risk for each unit is presented in Table 4.21-1. Therefore, any SAMA having an estimated single nuclear unit cost of implementation exceeding this value would not be considered cost-beneficial and was screened from further consideration.

The Maximum Averted Benefit (MAB) is dominated by offsite costs, both averted public radiation exposure and other offsite economic costs. The severe accident sequences that dominate the release of radioactivity offsite are from seismic and fire events that lead to small early releases and small late releases. The differences in the MAB between Unit 1 and Unit 2 are due to design differences between the units, most notably the presence of a dedicated auxiliary feedwater system at Unit 1 that is not present on Unit 2.

The next step involved performing a benefits analysis on the remaining SAMAs. The methodology for determining if a SAMA is beneficial consists of determining whether the benefit provided by implementation of the SAMA exceeds the expected cost of implementation. Since both Beaver Valley units have an external events PRA model, the expected cost of each unscreened SAMA was compared with a benefit considering both internal and external events. The benefit is defined as the reduction in the sum of the dollar equivalents for each severe accident impact (offsite exposure, offsite economic costs, occupational exposure, and onsite economic costs) resulting from the implementation of the SAMA.

The result of implementation of each SAMA would be a change in the Beaver Valley Unit 1 or Unit 2 severe accident risk (i.e., a change in frequency or consequence of severe accidents). The methodology for calculating the magnitude of these changes is straightforward. First, the severe accident risk after implementation of each SAMA is calculated using the same methodology as for the base case. The results of the Level 2 model were combined with the Level 3 model to calculate these post-SAMA risks. Next, the difference between the monetized value of the risk of the base case (before implementation of the SAMA) and the value of the risk after implementation of the SAMA was calculated; this represents the benefit of a specific SAMA. The results of the benefit analyses for each of the SAMAs are presented in Table 7-1 of Attachment C-1 and of Attachment C-2 for the respective units.

The SAMA evaluations were, in general, performed in a bounding fashion. Bounding evaluations were performed to address the generic nature of the initial SAMA concepts. Such bounding calculations overestimate the benefit and thus are conservative calculations. SAMAs were evaluated by making relatively simple, bounding changes to one or more system models and quantifying the full model. This resulted in a new set of plant damage bin frequencies which where analyzed to determine the impact on public risk. For example, one SAMA (SAMA 46 in both units) deals with providing an additional service water pump to reduce the contribution to core damage frequency from loss of service water (alternatively, this could be interpreted as increasing the reliability of the existing service water pumps); the bounding calculation to estimate the benefit of this improvement was to determine the impact of perfectly reliable service water pumps. Such a calculation obviously overestimates the benefit, but if the estimated costs to implement exceeded this inflated benefit then the SAMA was not cost-beneficial and was screened out.

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

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

where:

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

If the net value of a SAMA is negative, the cost of the enhancement is greater than the benefit and the SAMA is not cost beneficial. The expected cost of each SAMA (COE) was determined by either utilizing applicable cost estimates published in NRC submittals from other licenses or by expert judgment by knowledgeable Beaver Valley staff. The first step in the process was to review other submittals (e.g., the Watts Bar Nuclear Plant SAMDA evaluation). If previous submittals contained costs for a specific SAMDA (or SAMA), the enhancement description was reviewed to determine if the cost estimate could reasonably be applied to Beaver Valley, based on the Beaver Valley units' designs and licensing bases and knowledge of implementing plant modifications. If the previous licensee submittals did not contain cost estimates or if these cost estimates could not be applied at Beaver Valley, a review of the benefit was performed to determine whether the SAMA could be implemented for a cost equivalent to the benefit. Specific detailed cost estimates were not necessary to disposition the list of SAMAs. An expert panel formed of BVPS personnel and expert consultants with substantial experience and expertise in operations, design, maintenance, operating and emergency procedures, training, licensing, PRA, SAMA analysis was convened to review the results of the screening process to confirm and to concur in the results. The expert panel also provided its collective judgment into the costs associated with implementation of the unscreened SAMAs; the estimated costs developed by this panel were the costs with which the calculated benefits were compared. The expert panel also provided its insights, comments and concurrence with the conclusions reached by this analysis.

The cost-benefit comparison and disposition of each remaining SAMA are presented in Table 7-1 of Attachment C-1 and of Attachment C-2 for the respective units.

4.21.4 Sensitivity Analysis

NUREG/BR-0184 recommends using a 7% real (i.e., inflation-adjusted) discount rate for value-impact analysis and notes that a 3% discount rate should be used for sensitivity analysis to indicate the sensitivity of the results to the choice of discount rate. This reduced discount rate takes into account the additional uncertainties (i.e., interest rate fluctuations) in predicting costs for activities that would take place several years in the future. Analyses presented in Section 4.21.2 used the 7% discount rate in calculating benefits of all the unscreened SAMAs. FENOC also performed a sensitivity analysis by substituting the lower discount rate and recalculating the benefit of the candidate SAMAs

The following additional sensitivities were performed; each of the sensitivities produced a different benefit result for each of the SAMAs analyzed in the cost-benefit analysis. In addition to the discount rate sensitivity discussed above, the sensitivities performed were:

- Calculation of the benefit assuming a discount rate of 3%.
- Calculation of the benefit assuming a best estimate discount rate for FENOC of 8.37%.
- Calculation of the benefit assuming the core damage frequency was at the 95th percentile (upper bound) of the uncertainty distribution calculated for the core damage frequency.
- Calculation of the benefit assuming 29-year period for Unit 1 and 40-year period for Unit 2 in lieu of the base 20-year time frame.

The benefits calculated for each of these sensitivities are presented in Table 8-1 of Attachment C-1 and of Attachment C-2 for the respective units. This analysis considered as potentially cost-beneficial, those SAMAs whose upper bound sensitivity benefit value exceeded their cost estimate. This approach resulted in considering some SAMAs as potentially cost-beneficial that would have screened out had the basis for screening been solely their nominal benefit value.

4.21.5 Consideration of Alternatives for Reducing Adverse Impacts

FENOC evaluated many conceptual alternatives for mitigating severe accident impacts related to each BVPS unit (189 for Unit 1 and 190 for Unit 2). Preliminary screening eliminated 126 Unit 1 SAMAs and 134 Unit 2 SAMAs from further consideration, based on non-applicability to the units' design or features that have already been incorporated into the current design and/or procedures and programs. During the final disposition of the remaining SAMAs, many of the remaining SAMA candidates were eliminated (58 at Unit1 and 53 at Unit 2) because the cost was expected to exceed their benefit.

The SAMA analysis process identified 5 potentially cost beneficial SAMAs for Unit 1 and 3 for Unit 2 for consideration. These SAMAs will be considered by the plant management for implementation through the Beaver Valley Long-Term Plan development process. The potentially cost beneficial SAMA candidates for Unit 1 are provided in Table 4.21-2 and for Unit 2 in Table 4.21-3. Of the potentially cost beneficial SAMAs, none are aging related.

This cost benefit evaluation was performed using the 7% real discount rate recommended by NUREG/BR-0184 and NEI 05-01. The sensitivities performed for each of the SAMAs indicated that the results of the analysis are not significantly impacted by the discount rate that is assumed. A very conservative discount rate (3%) results in a large increase in the calculated benefit of the SAMAs. However, FENOC believes that the 7% discount rate is actually conservative because a more realistic discount rate of 8.37% is commonly used by FENOC to evaluate projects. Use of an 8.37% discount rate would result in lower benefits but would not alter the final screening results as can be seen in Attachments C-1 and C-2, Table 8-1.

4.21.6 Conclusions

As a result of this analysis, the SAMAs identified in Tables 4.21-2 and 4.21-3 have been identified as potentially cost beneficial, either directly or as a result of the sensitivity analyses. None of the potentially cost beneficial SAMAs are aging related. FENOC plans to implement Unit 1 SAMA 189 through the use of a portable pump that can provide makeup to the RWST. The necessary hardware is anticipated to be ready by the end of 2007. Since the other potential improvements could result in a reduction in public risk, these SAMAs will be entered into the Beaver Valley Long-term Plan development process for further consideration.

Implementation of Unit 1 and Unit 2 SAMA 164 would involve two actions. The first is a procedural change to direct the operators to close the RCS loop stop valves to isolate a steam generator that has had a tube failure. The second involves purchase or manufacture of a gagging device that could be used to close a stuck open steam generator safety valve (i.e., faulted) on the ruptured steam generator prior to core damage in SGTR events.

Implementation of Unit 1 SAMA 167 would involve installation of restraints on the masonry block walls of the emergency switchgear room. This would reduce failures of those walls following seismic events and prevent damage to the four emergency batteries located in the emergency switchgear rooms.

Implementation of Unit 1 SAMA 168 would involve installation of a fire barrier or fire curtain between the four emergency switchgear fans located in the cable spreading room. This would reduce propagation of a fire from one fan to another.

Implementation of Unit 1 SAMA 187 and Unit 2 SAMA 186 would involve modifications to increase the seismic ruggedness of the battery racks for the ERF substation diesel generator to be comparable with the emergency batteries; thereby increasing the ERF substation diesel generator availability following seismic events. These ERF substation batteries are not safety related.

Implementation of Unit 1 SAMA 189 involves purchasing a portable pump that can be used to provide makeup to the RWST. BVPS plans to implement this SAMA through an alternate mitigation strategy by the end of 2007.

Implementation of Unit 2 SAMA 3 would involve the purchase of a portable generator to supply power to the steam generator level instrumentation. The TDAFW pump does not require power to start or continue running.

Implementation of Unit 2 SAMA 78 would require removing the start-up feedwater pump skid (including main motor and associated auxiliary oil and seal water pumps and motors), and associated suction, discharge and recirculation piping and valves (including the current motor-operated and air-operated discharge valves). These components would be replaced by a smaller pump and motor skid, and associated piping and valves. The new suction and recirculation piping and valves would be run to an independent water source outside of the Turbine Building. The new discharge piping and valves (including a new motor-operated discharge valve), would be run to the abandoned location on the main feedwater header. Any disconnected, original power and control cabling (and associated circuit breakers, control switches and alarms) from the ERF Substation and Unit 2 Control Room would be reused where possible.

TABLE 4.21-1. ESTIMATED PRESENT DOLLAR VALUE EQUIVALENT FOR SEVERE ACCIDENTS

Parameter	Unit 1 Present Dollar Value ($)	Unit 2 Present Dollar Value ($)
Averted Public Exposure	$1,246,705	$1,203,099
Averted offsite costs	$3,483,791	$3,403,247
Averted occupational exposure	$7,402	$9,146
Averted onsite costs	$391,674	$482,500
Total	$5,129,572	$5,097,992

TABLE 4.21-2. POTENTIALLY COST BENEFICIAL SAMA CANDIDATES AT BVPS UNIT 1

BV1 SAMA Number	Potential Improvement	Discussion	Additional Discussion
164	Modify emergency procedures to isolate a faulted SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls.	Reduce failure of batteries due to seismic induced failure of battery room block walls.	
168	Install fire barriers for HVAC fans in the cable spreading room.	Eliminate failure of fire propagating from one fan to another.	
187	Increase seismic ruggedness of the ERF substation batteries. This applies to the battery rack only and not the entire structure.	Increased reliability of the ERF substation diesel following seismic events.	
189	Provide diesel backed power for the fuel pool purification pumps and valves used for makeup to the RWST.	Increased availability of the RWST during loss of offsite power and station blackout events.	BVPS plans to implement this SAMA through alternate mitigation strategies that provide portable pumps that can be used for RWST makeup by the end of 2007.

TABLE 4.21-3. POTENTIALLY COST BENEFICIAL SAMA CANDIDATES AT BVPS UNIT 2

BV2 SAMA Number	Potential Improvement	Discussion	Additional Discussion
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	This would provide a system similar to the dedicated AFW pump present at Unit 1.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	

4.22 REFERENCES

Note to reader: This list of references identifies web pages and associated URLs where reference data was obtained. Some of these web pages may likely no longer be available or their URL addresses may have changed. FENOC has maintained hard copies of the information and data obtained from the referenced web pages.

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5.0 ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION

NRC

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

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

While the NRC does not require an applicant's ER to contain analyses of the impacts of those environmental issues that have been generically resolved (10 CFR 51.53(c)(3)(i)), the Commission does 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 it 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 its GEIS conclusions (Ref. 5.0-1, page C9-13, Concern Number NEP.015).

FENOC considers new and significant information to be the following:

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

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

In the sections below, FENOC presents an overview of its processes for identifying new and significant information.

5.0.1 ROUTINE DISCOVERY AND EVALUATION PROCESSES

BVPS established two routine processes for discovery of potential new and significant information. First, in 2001, a BVPS administrative procedure for environmental emergency planning, preparedness, and response was revised to require yearly searches for offsite chemical hazards. The procedure directs the solicitation of information from the Beaver County Local Emergency Planning Committee (LEPC) about any new facilities or industries (or changes to existing ones) handling chemicals that pose a potential hazard to BVPS. If a new or changed facility is identified with the potential to impact BVPS, then an engineering request is initiated for further evaluation.

A second process, implemented by FENOC in 2002, requires due consideration of the 92 environmental issues identified in 10 CFR 51, Table B-1, before approving station changes, tests, and experiments (i.e., "proposed actions"). This environmental review, which is integrated with the FENOC 10 CFR 50.59 safety evaluation process, also considers other applicable or relevant standards (e.g., 40 CFR, 25 Pennsylvania Code) when judging the effects of proposed actions. Acceptance criteria for these effects include the environmental regulatory analyses supporting the current licensing basis.

5.0.2 LICENSE RENEWAL DISCOVERY AND EVALUATION PROCESS

FENOC implemented an additional multi-faceted approach to identify new and significant information specifically for BVPS license renewal:

- A review of internal and external documents and records including, but not limited to: environmental assessments and monitoring reports, procedures, and other management controls, compliance history reports, and environmental resource plans and data;
- Interviews with FENOC and FirstEnergy subject-matter experts regarding BVPS environmental impacts and the appropriateness of GEIS scope and conclusions with respect to BVPS; and
- Solicitation and review of information relevant to environmental impacts of BVPS and associated transmission lines from regulatory agencies and other stakeholder organizations.
- Information identified as a result of these activities was evaluated to determine its significance and documented.

Specifically, BVPS environmental personnel reviewed internal and external documents. They interviewed internal subject-matter experts, providing them with a written list of GEIS issue(s).

The interviews focused on three general and five issue-specific questions in an effort to discover new and potentially significant information, and participants were encouraged to identify any other information beyond those in the GEIS of which they may be aware. All responses were discussed, reviewed, and documented with concurrence from each individual.

With one exception, the license renewal discovery and evaluation process revealed no new information with the potential to be a significant environmental issue.

The one exception was a new propane pipeline terminal and wholesale distribution facility identified by several subject matter experts during the interview process. In addition, BVPS site personnel also identified the terminal in the FENOC Corrective Action Program and generated a condition report. Subsequently, an engineering assessment was conducted to evaluate the potential for risks or hazards as well as possible increases in design basis accidents at BVPS. The principal types of hazards that were considered included the potential for release of propane gas to incapacitate control room operators, overpressure resulting from the ignition and explosion of a vapor cloud, missile effects attributable to explosion debris, and thermal effects attributable to fires.

As a result of these engineering assessments of the propane pipeline terminal and distribution facility, it is concluded that either the hazard is not of consequence to the site or all postulated types of accidents from this offsite hazard having the potential to cause onsite accidents leading to the release of significant quantities of radioactive fission products have a sufficiently low probability of occurrence and fall within the scope of the low-probability-of-occurrence required by 10 CFR 100.20(b) based on criterion of 10 CFR 50.34(a)(1) as it relates to the requirements of 10 CFR Part 100. Therefore, all nearby facility and transportation accidents associated with the propane pipeline terminal and distribution facility, which could impact the safe operation of BVPS, do not pose an undue risk of public exposure and need not be considered as new design basis accidents at BVPS.

In addition to the engineering assessments, BVPS Environmental & Chemistry staff personnel conducted a separate evaluation to determine if the propane facility could affect BVPS operation to the extent that previous conclusions regarding environmental impacts may change. A review of the siting and operation of the propane pipeline terminal and distribution facility (including potential to affect air quality, water quality, solid waste generation, and traffic/transportation) was conducted as discussed in the routine assessment process outlined in Section 5.0.1. The evaluation showed that routine propane terminal operations would not result in significant impacts within the BVPS affected environment; thus it is concluded that such operations would not materially affect any environmental impact analyses or conclusion in the GEIS.

Based on the engineering assessments and the environmental staff evaluation that the environmental impacts of the propane pipeline terminal and distribution facility on BVPS were SMALL and would not invalidate the NRC conclusions found in the FES' for BVPS-1 and BVPS-2 and the GEIS, the propane terminal was concluded to be "new," but not "significant" information.

5.1 REFERENCES

5.0-1 U.S. Nuclear Regulatory Commission. *Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response*. NUREG-1529. Office of Nuclear Regulatory Research, Washington, D.C. May 1996.

6.0 SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS

6.1 LICENSE RENEWAL IMPACTS

FENOC has reviewed the environmental impacts associated with renewing the BVPS Units 1 and 2 operating licenses and has concluded that all of the impacts would be SMALL and would not require mitigation. This ER documents FENOC's basis for this conclusion. In Section 4.1, FENOC incorporates, by reference, the NRC's findings for the 54 Category 1 issues that apply to BVPS, all of which have impacts that are SMALL (see Attachment A). Chapter 4, Sections 4.2 through 4.21, presents FENOC's analysis of the 11 Category 2 issues that apply to the BVPS site. Results of these analyses indicate that impacts would be SMALL for all applicable Category 2 issues. Table 6.1-1 summarizes impacts that BVPS-1 and BVPS-2 license renewal would have on resources associated with all Category 2 issues.

TABLE 6.1-1

ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL OF BEAVER VALLEY POWER STATION UNITS 1 AND 2 (APPLICABLE CATEGORY 2 ISSUES[a])

No.	Issue	Environmental Impact
	Surface Water Quality, Hydrology, and Use (for all plants)	
13	Water-use conflicts (plants using cooling ponds or cooling towers using makeup water from a small river with low flow)	SMALL. Under low-flow conditions, BVPS consumptive use of Ohio River is only 1 percent of flow and the USACE maintains normal pool levels in the New Cumberland Pool.
	Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)	
25	Entrainment of fish and shellfish in early life stages	NONE. This issue is not applicable because BVPS-1 and BVPS-2 do not use once-through or cooling pond heat dissipation systems.
26	Impingement of fish and shellfish	NONE. This issue is not applicable because BVPS-1 and BVPS-2 do not use once-through or cooling pond heat dissipation systems.
27	Heat shock	NONE. This issue is not applicable because BVPS-1 and BVPS-2 do not use once-through or cooling pond heat dissipation systems.
	Groundwater Use and Quality	
33	Groundwater use conflicts (potable and service water, and dewatering; plants that use more than 100 gpm)	NONE. The issue is not applicable because the BVPS site uses no groundwater (no dewatering; potable and service water are from municipal supply).
34	Groundwater use conflicts (plants using cooling towers withdrawing makeup water from a small river)	SMALL. Under low-flow conditions, BVPS maximum consumptive use of Ohio River is estimated at only 1.5 percent of minimum expected flow based on the recorded 7Q10 flow, and the USACE maintains normal pool levels in the New Cumberland Pool.
35	Groundwater use conflicts (Ranney wells)	NONE. The issue is not applicable because BVPS does not use Ranney wells.
39	Groundwater quality degradation (cooling ponds at inland sites)	NONE. The issue is not applicable because BVPS does not use cooling ponds.
	Terrestrial Resources	
40	Refurbishment impacts to terrestrial resources	NONE. No impacts are expected because BVPS does not plan to undertake refurbishment.
	Threatened or Endangered Species	
49	Threatened or endangered species	SMALL. Other than some state-listed fish species, species of concern are not known to occur and generally have a low potential for occurrence (other than as transient individuals) in areas likely to be affected by plant and transmission line operation and associated maintenance; protective design, operation, and maintenance practices are employed; no significant land-disturbing activities are planned; and operational monitoring has not indicated significant adverse impacts on species of concern.

TABLE 6.1-1 (CONTINUED)

ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL OF BVPS-1 AND BVPS-2 (APPLICABLE CATEGORY 2 ISSUES[a])

No.	Issue	Environmental Impact
		Air Quality
50	Air quality during refurbishment (nonattainment and maintenance areas)	NONE. No impacts are expected because BVPS does not plan to undertake refurbishment.
		Human Health
57	Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	SMALL. BVPS site operations have had no known impact on public health due to thermophilic microbial pathogens. Risk of human health is low due to poor conditions for supporting populations of such organisms in the Ohio River, including areas affected by the thermal discharge, and low potential for exposure of the public in the thermally affected zone.
59	Electromagnetic fields, acute effects (electric shock)	SMALL. All circuits meet National Electrical Safety Code® requirements for limiting induced shock.
		Socioeconomics
63	Housing impacts	SMALL. BVPS is located in a high population area with no growth restrictions. NRC concludes that impacts to housing are expected to be of small significance at plants in areas with a high population ranking where growth-control measures are not in effect.
65	Public services: public utilities	SMALL. Excess water capacity in the region is sufficient to handle the license renewal population growth.
66	Public services: education (refurbishment)	NONE. No impacts are expected because BVPS does not plan to undertake refurbishment.
68	Offsite land use (refurbishment)	NONE. No impacts are expected because BVPS does not plan to undertake refurbishment.

TABLE 6.1-1 (CONTINUED)

ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL OF BVPS-1 AND BVPS-2 (APPLICABLE CATEGORY 2 ISSUES[a])

	Socioeconomics (continued)	
69	Offsite land use (license renewal term)	SMALL. No plant-induced changes to offsite land use are expected from license renewal. Impacts from continued operation would be positive
70	Public services: transportation	SMALL. Capacities of area roads are adequate and the increase in traffic flow as a result of license renewal would most likely be unnoticeable.
71	Historic and archaeological resources	SMALL. BVPS does not plan to undertake refurbishment. Ground disturbing activities conducted during the license renewal period would be performed in accordance with FENOC procedures that insure the protection of cultural resources.
76	Severe accidents	SMALL. FENOC identified 20 potentially cost beneficial SAMAs and is evaluating their implementation. None are related to aging management.

[a] FENOC adopts, by reference, the NRC's findings for applicable Category 1 issues, all of which have SMALL impacts. No impact analyses are presented for Issue 60, "Electromagnetic Field – Chronic Effects," which has been categorized "NA" by the NRC and for which the applicant is not required to provide an analysis (10 CFR 51.53(c)(3); 10 CFR 51, Subpart A, Appendix B, Table B-1) and Issue 92, "Environmental Justice," which will be addressed by the NRC in plant-specific reviews (10 CFR 51, Subpart A, Appendix B, Table B-1).

7Q10 = once-in-10-year, 7-day-duration low flow
BVPS = Beaver Valley Power Station
FENOC = FirstEnergy Nuclear Operating Company
gpm = gallons per minute
No. = issue number
NRC = U.S. Nuclear Regulatory Commission
USACE = U.S. Army Corps of Engineers

6.2 MITIGATION

NRC

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

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

Impacts of license renewal are SMALL except for a MODERATE, but beneficial, impact on the local school district tax revenue collection and do not require mitigation. However, FENOC has chosen to implement some mitigative measures, including employing persons to direct traffic during periods of congestion and adding biocides to cooling water being discharged to prohibit microbial growth. These mitigative measures would continue throughout a renewed term of plant operation. No new mitigative measures are planned for purposes of license renewal.

In addition to mitigative measures, current operations include monitoring activities that would continue during the license renewal term. FENOC performs routine monitoring to ensure the safety of workers, the public, and the environment. These activities include the radiological environmental monitoring program, air quality emissions monitoring, and effluent chemistry monitoring. These monitoring programs ensure that the plant's permitted emissions and discharges are within regulatory limits and any unusual or off-normal emissions/discharges are quickly detected.

FENOC's environmental review efforts included assessing the adverse impacts that may lead to cumulative impacts. In addition to considering past and present activities in the vicinity of BVPS, FENOC held discussions with USACE, water authority representatives, and regulatory and planning agencies to determine if any activities were in the planning stages that could lead to cumulative impacts. No future actions that would be expected to have impacts additive to the impacts from BVPS operation during the license renewal term were identified. BVPS's anticipated impacts on the existing conditions are described in Chapter 4 and, as stated above, would be SMALL or beneficial. No cumulative impacts are expected. The following sections discuss unavoidable adverse impacts, irreversible or irretrievable commitments of resources, and the relationship between local short-term use of the environment and long-term productivity.

6.3 UNAVOIDABLE ADVERSE IMPACTS

NRC
The environmental report shall discuss any "...adverse environmental effects which cannot be avoided should the proposal be implemented...." [10 CFR 51.45(b)(2)] as adopted by 51.53(c)(2)] The report "...should not be confined to information supporting the proposed action but should also include adverse information." [10 CFR 51.45(e)]

FENOC adopts, by reference, for this ER the NRC findings stated in the GEIS for applicable Category 1 issues (see Attachment A), including discussions of any unavoidable adverse impacts. In Chapter 4, FENOC examined the 21 Category 2 issues the NRC identified in the GEIS and the environmental justice issue and identified the following unavoidable adverse impacts of renewing the operating licenses for BVPS-1 and BVPS-2:

- The cooling water system would cause some consumptive use of the Ohio River to compensate for drift and evaporation losses from the cooling towers.
- The cooling towers and their vapor plumes would be visible from offsite. This visual impact would continue during the license renewal term.
- Procedures for the disposal of sanitary, chemical, and radioactive wastes would be intended to reduce adverse impacts from these sources to acceptably low levels. Solid radioactive wastes would be a product of plant operations and long-term disposal of these materials must be considered.
- Operation of BVPS would result in a very small increase in radioactivity in the air and water. However, fluctuations in natural background radiation would be expected to exceed the small incremental increase in dose to the local population. Operation of BVPS also would create a very low probability of accidental radiation exposure to inhabitants of the area.
- Limited numbers of adult and juvenile fish are impinged on the traveling screens at the cooling water intake structure.
- Very small numbers of larval fish are entrained at the cooling water intake structure.

Based on the discussion and analyses presented in Chapter 4 of this environmental report, FENOC expects that all unavoidable adverse impacts resulting from renewal of the BVPS operating licenses would be SMALL.

6.4 IRREVERSIBLE OR IRRETRIEVABLE RESOURCE COMMITMENTS

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

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

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

FENOC has not identified any activities during the license renewal term that would irreversibly or irretrievably commit additional resources beyond those committed during the construction and operation of BVPS-1 and BVPS-2 during their initial operating license terms and the preemption of land and consumption of materials such as those discussed above. Consistent with conclusions of the AEC and the NRC with regard to operations in the current license terms (Ref. 6.4-1, Section 8.4; Ref. 6.4-2, Section 8.4; Ref. 6.4-3, Section 6.2), FENOC concludes that these resource commitments are appropriate for the benefits gained by license renewal and extended operation of the BVPS units.

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

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

The current balance between short-term use and long-term productivity of the environment at the BVPS site was set in 1976, when BVPS-1 began operating. The AEC documented its evaluations of this balance in its FES for BVPS-1 and BVPS-2 (Ref. 6.4-1, Section 8.3; Ref. 6.4-2, Section 8.3). The NRC specifically confirmed the BVPS-2 evaluation in its FES for BVPS-2 operations, issued in 1985 (Ref. 6.4-3, Section 6.3). Of particular note in these evaluations was the conversion of approximately 22 acres of land to electric power generation facilities. Subsequent to the issuance of the construction-phase FESs, some additional land within the site boundary has been converted to plant operations use (Ref. 6.4-3, Sections 4.2.1 and 4.2.2). The AEC noted that, upon decommissioning, much of the facility could be dismantled and restored to its original condition for the long term.

The annual consumption of 20 cfs (14,000 acre-feet) per unit (i.e., 40 cfs [29,000 acre-feet] for both units combined) of Ohio River water was also noted by the AEC in the initial FESs (Ref. 6.4-1; Ref. 6.4-2). The AEC and the NRC, with respect to BVPS, concluded that resource is renewed seasonally and the only temporary effect, to preclude that amount of water being available for downstream users, does not involve a significant volume. As indicated in Section 3.1.3.3, estimated annual consumption of Ohio River water has increased to 45 cfs (33,000 acre-feet per year) since that time, a result of power uprate for the BVPS units. However, this increase is small and does not alter the basis of the initial conclusion of the AEC and NRC (Ref. 6.4-4).

FENOC notes that the current balance is now well established and can be expected to remain essentially unchanged by the renewal of the operating licenses and extended operation of BVPS. Extended operation of BVPS-1 and BVPS-2 would postpone restoration of the site and its potential availability for other uses. It would also result in other short-term impacts on the environment, all of which have been determined to be SMALL on the basis of the NRC's evaluation in the GEIS and FENOC's evaluation in this ER.

6.6 REFERENCES

6.4-1 U.S. Atomic Energy Commission. *Final Environmental Statement Related to Operation of the Beaver Valley Power Station Unit 1; Duquesne Light Company, Ohio Edison Company, and Pennsylvania Power Company.* Docket No. 50-334. Directorate of Licensing, Washington, D.C. July 1973.

6.4-2 U.S. Atomic Energy Commission. *Final Environmental Statement Related to the Beaver Valley Power Station Unit 2; Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, and Toledo Edison Company.* Docket No. 50-412. Directorate of Licensing, Washington, D.C. July 1973.

6.4-3 U.S. Nuclear Regulatory Commission. *Final Environmental Statement Related to the Operation of Beaver Valley Power Station, Unit 2. Duquesne Light Company, et al.* Docket No. 50-412. Office of Nuclear Reactor Regulation, Washington, D.C. September 1985.

6.4-4 U.S. Nuclear Regulatory Commission. *Beaver Valley Power Station, Unit Nos. 1 And 2 Final Environmental Assessment and Finding of No Significant Impact Related to The Proposed License Amendment to Increase The Maximum Reactor Power Level, FirstEnergy Nuclear Operating Company, et al.* Docket Nos. 50-334 and 50-412. Office of Nuclear Reactor Regulation, Washington, D.C. July 2006. Accession Number ML061770605. Accessed March 2007.

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7.0 ALTERNATIVES TO THE PROPOSED ACTION

NRC

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

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

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

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

The NEPA requires the NRC to consider the environmental impacts of the proposed action (i.e., license renewal) and alternatives to the proposed action when deciding whether to approve renewal of an applicant's operating license. In this chapter, FENOC identifies reasonable alternatives to renewal of the BVPS Units 1 and 2 operating licenses and presents its evaluation of associated environmental impacts. This chapter also includes descriptions of alternatives FENOC considered, but determined to be unreasonable to consider in detail, and associated supporting rationale.

In Section 7.1, FENOC addresses the "no-action" alternative in terms of the potential environmental impacts of not renewing the BVPS operating licenses, independent of any actions taken to replace or compensate for the loss of generating capacity. In Section 7.2, FENOC describes feasible alternative actions that could be taken, which FENOC also considers to be elements of the no-action alternative, and presents other alternatives that FENOC does not consider to be reasonable. Section 7.3 presents environmental impacts for the reasonable alternatives.

The environmental impact evaluations of alternatives presented in this chapter are not intended to be exhaustive. Rather, the level of detail and analysis rely on the NRC's decision-making standard for license renewal, as follows:

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

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

FENOC characterizes environmental impacts in this chapter using the same definitions of "SMALL," "MODERATE," and "LARGE" used in Chapter 4 of this ER and by the NRC in its GEIS (Ref. 7.0-1). In Chapter 8, FENOC presents a summary comparison of environmental impacts of the proposed action and alternatives.

7.1 NO-ACTION ALTERNATIVE

FENOC considers the no-action alternative addressed in this ER to be a scenario in which the NRC does not renew the current BVPS operating licenses, FENOC ceases operating BVPS-1 and BVPS-2 upon expiration of their respective licenses in 2016 and 2027 and decommissions the facilities, and FirstEnergy and/or others take appropriate actions to meet system-generating needs created by discontinued operation of the Units. In Section 7.1.1, FENOC addresses the impacts of terminating operations and decommissioning, exclusive of actions to replace power from BVPS, which is introduced in Section 7.1.2.

7.1.1 Terminating Operations and Decommissioning

In the event the NRC does not renew the BVPS operating licenses, FENOC assumes for this ER that it would operate the units until their current licenses expire, then terminate operations and initiate decommissioning activities in accordance with NRC requirements. For purposes of this discussion, terminating operations includes those actions directly associated with permanent cessation of operations, which may result in more or less immediate environmental impacts (e.g., socioeconomic impacts from reduction in employment and tax revenues). Decommissioning, defined by the NRC at 10 CFR 50.2, denotes the safe removal from service of a nuclear generating facility and the reduction of residual radioactivity to a level that permits release of the property for unrestricted or restricted use and termination of the license. Additional activities, such as dismantlement of major plant structures (e.g., intake and discharge structures, cooling towers) for purposes other than reduction of residual activity, are closely associated with, but not necessarily wholly included in, the decommissioning process. The NRC provides more detailed descriptions of these activities in the GEIS (Ref. 7.0-1, Chapter 7 and Section 8.4) and its Supplement 1 to the *Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* (NUREG-0586, Supplement 1) (Ref. 7.1-1, Sections 1.3 and 3.2).

The two decommissioning options typically selected for United States reactors are referred to as DECON and SAFSTOR (Ref. 7.1-1, Section 3.2). Under the DECON option, radioactively contaminated portions of the facility and site are decontaminated or removed promptly after cessation of operations to a level that permits termination of the license; these activities require several years for large light-water reactors like BVPS (Ref. 7.1-1, Section 3.3). The SAFSTOR option involves safe storage of the stabilized and defueled facility for a period of time followed by decontamination to levels that permit license termination. Regardless of the option chosen, decommissioning typically must be completed within 60 years after operations cease in accordance with NRC requirements at 10 CFR 50.82 (Ref. 7.0-1, Section 7.2; Ref. 7.1-1, Section 3.2).

FENOC has not selected a decommissioning method for BVPS. However, DECON is a likely option for both units, and reasonable potential exists that FENOC would use SAFSTOR for BVPS-1 until expiration of the BVPS-2 operating license to take advantage of potential economies of scale for decontamination and related activities and to minimize potential disruption of BVPS-2 operations. Decommissioning methods for BVPS would be described in post-shutdown decommissioning plans for the units, which must be submitted to NRC within 2 years following cessation of operations. Related NRC requirements ensure that the decommissioning activities, when defined, would be subject to required environmental reviews in accordance with NEPA (10 CFR 50.82). For purposes of the present analysis, FENOC assumes that the DECON option would be employed upon license termination for each of the BVPS units. This approach simplifies the analysis by not considering potential additive or synergistic decommissioning impacts resulting from simultaneous DECON operations at both units. In addition, this assumption provides a more appropriate basis for FENOC's adoption of decommissioning methods and impact conclusions developed by the NRC in other NEPA documents, as described below.

The NRC presents in the GEIS (Ref. 7.0-1, Chapter 7 and Section 8.4) a summary of generic environmental impacts of the decommissioning process and, in the interest of thoroughly examining potential consequences of the proposed action (license renewal), an evaluation of potential changes in impact that could result from deferring the decommissioning process for up to 20 years. The NRC bases that summary and evaluation on information from its *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities,* NUREG-0586, issued in 1988 (Ref. 7.1-2), and related documents. Its discussion of pressurized water reactor (PWR) decommissioning used the 1,175- MWe Trojan Nuclear Plant as a basis. This "reference PWR" is comparable in size to each of the BVPS reactors (see Section 3.1.2). Therefore, FENOC considers the reference reactor to be representative of the BVPS units and considers the decommissioning activities described in the GEIS to be representative of activities FENOC would perform for decommissioning at BVPS. The NRC concluded from its evaluation that decommissioning impacts would not be significantly greater as a result of the proposed action, assumed to result in 20 additional years of operation (Ref. 7.0-1, Sections 7.3 and 8.4; 10 CFR 51, Subpart A, Appendix B, Table B-1). The NRC conclusions presented in 10 CFR 51, Subpart A, Appendix B, Table B-1, also indicate that the impacts of the decommissioning process itself, addressed here as part of the no-action alternative, would have small impacts with respect to radiation dose, waste management, air quality, water quality, and ecological resources. FENOC considers this generic evaluation and associated conclusions appropriate to BVPS for purposes of this ER.

In Supplement 1 to NUREG-0586 (Ref. 7.1-1), the NRC provides an update of its 1988 generic environmental impact evaluation of decommissioning nuclear power reactors and addresses the impacts of associated demolition activities. The generic evaluation draws from decommissioning experience gained since issuance of the 1988 document, including that from 19 commercial power reactor facilities in the decommissioning process. In addition, the NRC considers in the generic evaluation the attributes and characteristics of the remaining 104 operating plants in the United States, including BVPS, to ensure its appropriateness for future decommissioning of these plants (Ref. 7.1-1, pages xii and 3-1). In its evaluation, the NRC addressed a full range of environmental issues, categorized them as generic or site-specific, and assigned NRC's standard impact significance levels of SMALL, MODERATE, and LARGE (i.e., the same significance levels used in this ER; see Section 4.1.2) to the site-specific issues. Of the 23 environmental issues evaluated, the NRC concluded that the following issues were site-specific: impacts on land use from offsite activities, impacts on aquatic and terrestrial ecology and cultural and historic resources from activities beyond operational areas, impacts on threatened and endangered species, and environmental justice impacts. The NRC concluded that all of the remaining issues were generic with small impacts (Ref. 7.1-1, Table ES-1).

In consideration of the above and based on its review of Supplement 1 to NUREG-0586, FENOC considers the generic description of decommissioning and associated demolition activities and the generic evaluation and associated conclusions presented in that document to be appropriate to BVPS for purposes of this ER. Further, FENOC has no reason to believe at this time that decommissioning activities would involve significant land-use disturbance offsite or significant activities beyond current operational areas that would offer potential for impacts on land use, ecological resources, or cultural resources.

In summary, the environmental impacts associated with terminating operations and decommissioning provide little or no basis for discriminating between the proposed action and the no-action alternative, except for potential adverse socioeconomic impacts associated with terminating plant operations 20 years earlier than would occur if the BVPS operating licenses were renewed, as discussed above. The environmental impacts of replacement options considered in Section 7.3 provide substantial additional information useful for evaluating the relative environmental merits of the proposed action versus the no-action alternative.

7.1.2 Replacement Capacity

BVPS is a base-load generator of electric power. The net generating capabilities of BVPS-1 and BVPS-2 are approximately 924 MW and 918 MW, respectively, for a total net generating capability of 1,842 MW (see Section 3.1.1). In 2005, BVPS generated 13,970,312 MWe (Ref. 7.1-3), approximately 17 percent of FirstEnergy's total electricity generation. The power produced by BVPS, which represents a significant portion of the electricity FirstEnergy supplies to 4.5 million customers in its service territories located in Ohio, Pennsylvania, and New Jersey (Ref. 7.1-4), would be unavailable in the event the BVPS operating licenses are not renewed. As provided in 10 CFR 51.53(c)(2), FENOC does not consider the need for power from BVPS in this analysis, but does consider the potential impact of alternatives for replacing this power. Replacement options considered include building new base-load generating capacity, purchasing power, delaying retirement of non-nuclear assets, and reducing power requirements through demand reduction, as discussed in Section 7.2.

7.2 ALTERNATIVES THAT MEET SYSTEM GENERATING NEEDS

In Section 7.2.1, FENOC provides general background information pertinent to the identification and selection of options available to replace generating capability that would be lost in the event the BVPS operating licenses are not renewed. Section 7.2.2 provides more specific information about alternatives FENOC considers reasonable. These include new natural gas-fired generation (Section 7.2.2.1) and new coal-fired generation (Section 7.2.2.2). Section 7.2.3 describes other alternatives evaluated and FENOC's rationale for not considering them to be reasonable options for replacing power produced by BVPS.

7.2.1 General Considerations

Although BVPS is located in Pennsylvania, it is within 5 miles of Ohio and West Virginia, essentially at the junction of these three states (see Section 2.1). In addition, the service territories of FirstEnergy's electric utility operating companies include portions of Ohio, Pennsylvania, and New Jersey, which lie within the Reliability*First* Corporation (RFC) region of the North American Electric Reliability Council (NERC) (Ref. 7.2-1). NERC approved RFC to become one of eight regional reliability councils effective January 1, 2006. RFC is the successor organization to three NERC regional reliability councils: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN). Considering also the impact of deregulation, discussed in Section 7.2.1.1 below, FENOC has taken a regional approach in Section 7.2.1, which presents general considerations related to replacement of power from BVPS in the event its operating licenses are not renewed.

7.2.1.1 Regulatory Background

The BVPS is located within the service territory of Duquesne Light Company. In 2005, with the decision of Duquesne to join the PJM Interconnection, LLC (PJM), BVPS became a part of the PJM regional transmission organization (RTO) footprint. PJM encompasses a region that includes more than 164,000 square miles in 13 states and the District of Columbia. The peak demand in the PJM footprint was 144,644 MW during the summer of 2006. PJM has installed generation capacity of nearly 165,000 MW (Ref. 7.2-31, page 2). PJM expects its demand for capacity to reach 220,000 by 2020, necessitating 55,000 MW of new generation and demand response, or the equivalent of adding three large nuclear power plants to the system annually for the next 13 years (Ref. 7.2-31, page 26).

PJM operates the world's largest competitive wholesale electricity market and ensures the reliability of the largest centrally dispatched grid in the world. PJM's members, totaling more than 450, include power generators, transmission owners, electricity distributors, power marketers and large consumers. PJM's role as a federally regulated RTO means that it acts independently and impartially in managing the regional transmission system and the wholesale electricity market. PJM is the tariff administrator, reliability coordinator, and transmission provider within its footprint pursuant to a Federal Energy Regulatory Commission (FERC) approved open access transmission tariff. PJM also administers competitive wholesale markets for capacity, energy, and ancillary services. PJM has certain operational control over BVPS under its tariff and generator interconnection agreement.

The output of BVPS is sold to FirstEnergy Solutions Corporation, a licensed wholesale power marketer, which participates in the PJM capacity, energy, and ancillary services markets. The output of the BVPS is used primarily to supply a portion of the provider of last resort power requirements of its regulated affiliates, Metropolitan Edison Company and Pennsylvania Electric Company. Metropolitan Edison Company and Pennsylvania Electric Company purchase transmission service from PJM for delivery of power from the BVPS.

BVPS is also connected by transmission lines to facilities under the operational control of the Midwest Independent Transmission System Operator, Inc. (MISO). The MISO is a regional transmission organization operating in 15 different states and the province of Manitoba. MISO has a peak demand of 136,520 MW and installed generation capacity of 162,981 MW (Ref. 7.2-32, page 18). With the exception of BVPS, virtually all of FirstEnergy's generating facilities are located within the MISO. MISO is the transmission operator, reliability coordinator, and market administrator for its region.

FirstEnergy's generation and transmission facilities, including BVPS, are located within the reliability region supervised by RFC. With the passage of the Energy Policy Act of 2005 Congress established a regime of mandatory reliability standards for generation and transmission owners and operators, as well as other entities. NERC was certified by the FERC as the electric reliability organization responsible for establishing and enforcing mandatory reliability standards. These standards are subject to review and approval by the FERC. NERC has entered into a regional delegation agreement with RFC whereby RFC has assumed primary responsibility for enforcement of the reliability standards.

Virtually all of the states within PJM, and FirstEnergy's Ohio service territory within MISO, have introduced retail competition for the supply of generation. The introduction of retail competition by states has resulted in restructuring of utility companies to separate generation, transmission, and distribution of electricity. For example, FirstEnergy's generation assets are now owned or operated by its subsidiary companies, FirstEnergy Generation Corporation and FirstEnergy Nuclear Generation Corporation. FENOC continues to operate the nuclear plants owned by FirstEnergy. FirstEnergy's transmission facilities within MISO are owned and operated by American Transmission Systems, Inc, which is functionally separate from other subsidiaries, including FENOC, that operate generation assets. As noted above, the transmission assets owned by FirstEnergy subsidiaries are under the operational control of the MISO and PJM, respectively.

Through the issuance of Orders 888 and its progeny, the Federal Energy Regulatory Commission has mandated equal access to transmission lines by generation suppliers, thus facilitating state restructuring efforts to promote competition by allowing retail customers to choose among qualified suppliers (Ref. 7.2-2). For example, the General Assembly of Pennsylvania enacted the *Electricity Generation Customer Choice and Competition Act* in November 1996, which enables all customers of electric distribution companies in the Commonwealth to purchase electricity from their choice of licensed electric generation suppliers (i.e., generator and supplier, aggregator, and/or broker/marketer) (Ref. 7.2-4; Ref. 7.2-5). Forty-three competitive electric suppliers were licensed in Pennsylvania as of November 2006 (Ref. 7.2-6). Ohio's retail electric market was opened to competition in 2001, and 38 suppliers were initially certified to sell electricity to all customer classes (Ref. 7.2-7). As of March 2007, 48 competitive electric suppliers were certified in Ohio (Ref. 7.2-17). In January 2000, the West Virginia Public Service

Commission issued an order finding that restructuring traditional electric utility supply, opening supply markets, and offering customer choice of supplier was in the public interest and set forth its plan for transition to competitive markets and customer choice (Ref. 7.2-8). However, as of April 2006, the West Virginia Legislature had not passed implementing legislation (Ref. 7.2-9). Other states within the PJM footprint such as Maryland, and New Jersey conduct competitive solicitations for power supply for all retail customers who do not select competitive retail electric suppliers.

These restructuring initiatives are designed to establish an environment in which numerous electric generators, including independent merchant generators, may participate in wholesale and retail power markets, and customers may choose their source of supply based on their needs and preferences, price, or other criteria. This competitive market environment also permits the participation of demand-side management (DSM)-related resources that are economical.

In addition, deregulation of electricity generation and implementation of this market-based system, with oversight by state public utility commissions, are designed to promote competition among suppliers and, therefore, introduce uncertainties into the type and amount of new generation that will be developed in the future. In a competitive market, it is not clear whether FirstEnergy or another competitive supplier would construct new generating units to replace those at BVPS if its operating licenses are not renewed.

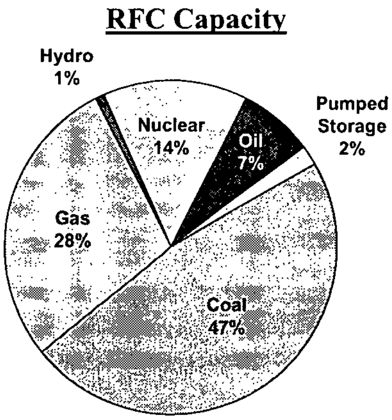
7.2.1.2 Capacity and Utilization

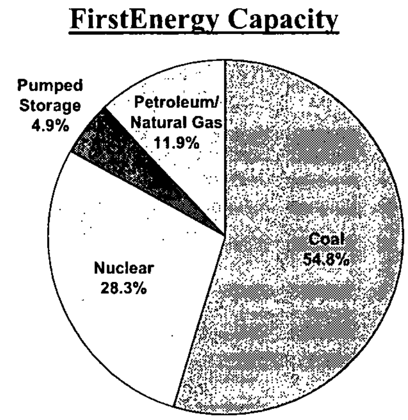
Current and anticipated future electric power generating capability and utilization in the RFC region reflects the nature of energy markets and the technical and economic viability of technologies for generating electricity and, therefore, offer the most appropriate insight regarding potentially reasonable alternatives to replace power produced by BVPS. As indicated in Figure 7.2-1, coal-fired power plants account for 47 percent of generating capacity in RFC, with another 14 percent of capacity being nuclear fueled. This 61 percent of the capacity is primarily base and intermediate duty generation. Oil and natural gas fuel 7 percent and 28 percent of the capacity respectively, and 3 percent of the capacity is hydroelectric or pumped storage. The remaining 1 percent of the capacity uses a variety of renewable and other energy supplies (Ref. 7.2-16, page 83). FirstEnergy's generating capability is primarily coal-fired (54.8 percent) and nuclear (28.3 percent). Natural gas- and oil-fired facilities represent 11.9 percent and pumped storage represents 4.9 percent of FirstEnergy's generating portfolio (Ref. 7.2-12).

The *Long Term Resource Assessment 2007-2016* published by RFC shows that electric capacity margins are expected to decline over the 2007-2016 study period. When planned capacity additions of 15,416 MWs are taken into account, the total capacity is insufficient to maintain a 15 percent reserve margin through 2012. The earliest date when the reserve margin would be less than 15 percent would be 2008, if no new capacity is completed. If the proposed capacity projects are not completed as scheduled and the transmission system is incapable of fully delivering all existing capacity, a reduction of the entire 15,416 MW of capacity resources would reduce the reserve margin in 2016 to 1.6 percent (Ref. 7.2-16, page 9).

FIGURE 7.2-1

2005 ELECTRIC CAPACITY





Source: RFC capacity from Ref. 7.2-16, page 83. FirstEnergy capacity from Ref. 7.2-12.

The increase in generating capacity from renewable sources is projected to total 4800 MW in RFC through 2016 (Ref. 7.2-16). These projections take into account federal subsidies for renewables, state mandates, and renewable portfolio standards (RPSs) (i.e., standards requiring a minimum percentage of electric supply from renewable sources) currently in effect (Ref. 7.2-16). Renewables could account for a greater share of the generation mix than RFC currently projects as a result of future federal or state RPS initiatives. For example, if passed, the *Securing America's Energy Independence Act* (i.e., Senate Bill 590, House Bill 550) would lead to greater generation from renewable sources (Ref. 7.2-28).

7.2.1.3 Regulatory Considerations for Air Quality

Use of either natural gas-fired or coal-fired generation technologies would be subject to air emission controls and limits established in accordance with applicable EPA regulations (40 CFR 50-99) as well as applicable state regulations. A plant using these technologies to replace generating capability from BVPS potentially could be located in Pennsylvania or other nearby states, including Ohio or West Virginia (see Section 7.2.1). As discussed below in Section 7.2.2.1, FENOC assumes for purposes of this alternatives analysis that a new gas-fired plant would be developed in Ohio. Similarly, FENOC assumes in Section 7.2.2.2 that a new coal-fired plant would be developed along a navigable river in the region, which could reasonably include a site in Ohio. Therefore, the following discussion highlights regulatory considerations for air quality applicable to development of a plant in Ohio; similar controls would be applicable to plants developed elsewhere in the region.

The *Ohio Administrative Code* (OAC), Chapter 3745-31, provides that a permit-to-install be obtained from the Ohio Environmental Protection Agency (Ohio EPA) before construction of any new facility can begin. The requirements to obtain a permit for a major new power plant in Ohio include the following:

- Federal new source performance standards (NSPS);
- Federal and Ohio rules for prevention of significant deterioration (PSD) for siting new major sources in air quality attainment areas and/or the federal and Ohio rules for nonattainment new source review for siting major new sources in air quality nonattainment areas;
- Requirements pursuant to the Ohio nitrogen oxides emissions trading program;
- Requirements related to the federal *Clean Air Act* Title IV acid rain control program; and
- State of Ohio requirements for best available technology and acceptable environmental impact.

As a minimum standard, any new fossil-fired facilities would be required to comply with the NSPS set forth by EPA at 40 CFR Part 60. For a large bituminous coal-fired power plant, the NSPS generally require that particulate matter emissions must be reduced by more than 99 percent from uncontrolled levels and must not exceed 0.03 pounds per million British thermal units (lb/MMBtu) heat input. Sulfur dioxide emissions must be reduced by at least 90 percent from uncontrolled levels and must not exceed 1.20 lb/MMBtu, and nitrogen oxide emissions (expressed as nitrogen dioxide) must not exceed 0.50 lb/MMBtu (for sub-bituminous coal combustion) or 0.60 lb/MMBtu (for bituminous or anthracite coal combustion). For large natural-gas turbines, the NSPS for nitrogen oxide emissions is a calculated value that depends on fuel-bound nitrogen and heat rate of the unit, generally amounting to approximately 75 parts per million (ppm); sulfur dioxide emissions are limited to 0.015 percent by volume at 15 percent oxygen (dry basis); and fuel must contain sulfur less than 0.8 percent by weight.

The NSPS are seldom the limiting factor for air permitting. Emission limits for individual plants are generally established on the basis of air emission source designation, attainment status of potentially affected areas with respect to air quality standards, technology and fuel type, and related factors. The two basic sets of regulations for new power plants are determined by whether the area where the proposed source is to be located is classified as "attainment" or "nonattainment" for one or more of the NAAQS.

If a facility is located in an area that is in attainment or unclassified with respect to the NAAQS, such as is the case for most of the state of Ohio, the plant would qualify as a major source subject to the new source review provisions of the PSD rules set forth under OAC rule 3745-31-11 through OAC rule 3745-31-20. Under these provisions, emission limits are established on the basis of best available control technology (BACT) for regulated pollutants that exceed established PSD significant emission rates and a demonstration that specified air quality deterioration increments as well as ambient air quality standards would not be jeopardized. If the facility is located in a nonattainment area with respect to one or more NAAQS pollutants, emission rates for the nonattainment contaminants would be established under nonattainment new source review provisions set forth under OAC rule 3745-31-21 through OAC rule 3745-31-27. In this case, emission standards for the nonattainment contaminants are established on the basis of the more stringent lowest achievable emission rate (LAER). In addition, offsets of 1:1 or more could be required for nonattainment contaminant emissions.

Because nitrogen oxide is an ozone precursor, emissions of this pollutant are subject to the nitrogen oxide allowance management plan implemented by Ohio in accordance with EPA's nitrogen oxides SIP call (63 FR 57356, October 27, 1998). Large fossil fuel-fired electric generating units are subject to a cap on nitrogen oxide emissions through a market-based trading system under Ohio's nitrogen oxide budget trading program set forth in OAC chapter 3745-14. Under this program, each affected source must have allowances for each ton of nitrogen oxides actually emitted during the ozone season (May 1 through September 30). The allowances were allocated to existing sources based on an emission rate of 0.15 lb/MMBtu for a historical baseline ozone season. Nitrogen oxide allowances for new sources are available from a special allocation known as the "new source set-aside" specified in OAC rule 3745-14-05(C)(4)(a) as 5 percent of the total state trading program budget. It is uncertain, however, if the set-aside will be adequate to meet the needs of all proposed new sources. As a result, further restrictions in the nitrogen oxide emissions rate may be required for the proposed new unit and/or other existing units to reconcile total nitrogen oxide emissions at year-end.

The federal *Clean Air Act* acid rain provisions (Title IV) are a particular concern with respect to sulfur dioxide emissions from a coal-fired power plant. These provisions cap aggregate sulfur dioxide emissions from power plants and established a market-based trading system for sulfur dioxide allowances. Development of a new coal-fired plant would require acquisition of allowances sufficient to cover sulfur dioxide emissions from the plant and/or further reductions in sulfur dioxide emissions rates from other facilities to reconcile total sulfur dioxide emissions at year-end.

In March 2005, the EPA finalized the Clean Air Interstate Rule (CAIR), which mandates limits on sulfur dioxide and nitrogen oxide emissions in 28 eastern states, including Ohio (70 FR 25162). The limits for sulfur dioxide emissions are 3.6 million tons beginning in 2010 and 2.5 million tons starting in 2015. The corresponding limits for nitrogen oxide emissions are 1.5 million tons in 2009 and 1.3 million tons in 2015. CAIR encourages a cap-and-trade approach to meeting those limits. The Ohio EPA has drafted rules to establish a cap-and-trade program for annual and seasonal emissions of nitrogen oxides and sulfur dioxide as a participant in the federal CAIR multi-state trading program (OAC draft rule 3745-109). Development of new fossil fuel-fired plants would require acquisition of allowances sufficient to cover sulfur dioxide and nitrogen oxide emissions from the plant and/or further reductions in those emission rates from other facilities.

More stringent performance standards may be applied by the Ohio EPA to supplement the regulations reviewed above. For example, OAC rule 3745-31-05(A)(3) requires that the new source employ the best available technology and OAC rule 3745-31-05(C) allows the Director of Ohio EPA to consider social and economic impact or other adverse environmental impact that may be a consequence of issuance of the permit to install. Although Ohio EPA seldom invokes these provisions to supplement the other applicable requirements reviewed above, it is possible that a major new power plant could be subject to additional requirements.

7.2.1.4 Mixtures

The NRC indicated in the GEIS that, while many methods are available for generating electricity and a huge number of combinations or mixes can be assimilated to meet system needs, such expansive consideration would be too unwieldy given the purposes of the alternatives analysis. Therefore, NRC determined that a reasonable set of alternatives should be limited to analysis of single discrete electrical generation sources and only those electric generation technologies that are technically reasonable and commercially viable (Ref. 7.0-1, Section 8.1). Consistent with the NRC determination, FENOC has not evaluated mixes of generating sources; however, the impacts from all coal- or all gas-fired generation presented in this chapter are expected to bound impacts from any generation mixture of the two technologies.

7.2.2 Feasible Alternatives

In view of the background information presented in Section 7.2.1, FENOC considers that new generating capacity represented by modern natural gas combined-cycle and pulverized coal-fired steam technologies are reasonable alternatives for purposes of this analysis to replace BVPS generating capacity of 1,842 MW in the event the BVPS operating licenses are not renewed. As discussed in the GEIS (Ref 7.0-1, Section 8.3.10), natural gas combined-cycle plants are particularly efficient and are used as base-load facilities. The specific coal-generating technologies that would represent viable alternatives in 2016 and 2027 when the BVPS operating licenses expire are less certain, particularly in view of potentially higher air emissions compared to natural gas firing. FENOC notes that large-capacity integrated gasification combined-cycle (IGCC) and fluidized-bed-combustion (FBC) technologies (atmospheric and pressurized) are at or near commercial viability and could prove to be appropriate replacements. However, modern pulverized coal plants with advanced, clean-coal technology air emission controls represent currently proven technology and are economically competitive and commercially available in large-capacity unit sizes that could effectively replace the BVPS units. Therefore, FENOC uses a representative plant of this type for purposes of impact evaluation, noting that air emission impacts of IGCC and FBC options may be lower than modern pulverized coal, but would be higher than the gas-fired combined-cycle alternative (Ref. 7.2-15, pages 5-7).

Regardless of the entity that constructed and operated the replacement power sources, certain environmental parameters would be constant among them. Therefore, this analysis addresses the impacts of reasonable alternatives to BVPS without regard to whether they would be owned or operated by FirstEnergy.

Descriptions of these alternatives are provided in Sections 7.2.2.1 and 7.2.2.2. Other alternatives evaluated by FENOC and reasons for not considering them in detail are presented in Section 7.2.3.

7.2.2.1 Representative Natural Gas-Fired Generation

For purposes of this analysis, FENOC assumed development of a modern natural gas-fired combined-cycle plant based on a commercially available design that could be readily configured as a base-loaded facility to replace power currently generated by BVPS. Basic design and operating assumptions are listed in Table 7.2-1. The assumed representative plant would consist of three General Electric S207FA units and one General Electric S107FA unit. The S207FA units each would consist of two combustion turbines (CTs) with associated heat recovery steam generators (HRSGs) that would supply steam to a single steam turbine generator ("two-on-one" configuration). The S107FA unit would consist of a single CT and an associated HRSG. This configuration would provide a combined net generating capacity of approximately 1,853 MW, comparable to the BVPS net capacity of 1,842 MW (Table 7.2-1).

FENOC assumed for conservatism in this comparative analysis that the representative plant would use natural gas as its only fuel. However, the facility reasonably could be constructed with capability to fire oil as a backup fuel for use during high demand periods for natural gas, thus improving fuel supply capabilities and operating cost. Based on the information presented in Table 7.2-1, total annual heat input from natural gas would be approximately 85,680,000 MMBtu per year, corresponding to natural gas consumption of approximately 83.6 billion cubic feet per year, as shown in the calculation below.

> Annual Natural Gas Requirement = [Natural Gas Heat Input] x [Heating Value of Fuel] = [Total Gross Capability (1,881 MW) x Heat Rate (6,500 Btu/kW-hour) x 1,000 kW/MW x Capacity Factor (0.8) x 8,760 hr/yr] x [Heating Value of Fuel (1 ft^3/1,025 Btu)]. Therefore: Natural Gas Heat Input = 8.568×10^{13} Btu/yr, or 8.568×10^{7} MMBtu/yr, and Annual Natural Gas Requirement = 8.359×10^{10} ft^3/yr, or 83.6 billion ft^3/yr.

The facility would be designed to meet applicable standards with respect to control of air and wastewater emissions. As a minimum, FENOC assumed that the plant would feature water/steam injection to minimize formation of nitrogen oxides during combustion and selective catalytic reduction for post-combustion nitrogen oxide control. Emissions of particulate matter and carbon monoxide would be limited through proper combustion controls. Exhaust from the CTs would be dispersed through individual stacks for each of the four units, which FENOC assumed would be at least 150 feet high. For purposes of siting flexibility and simplicity in the analysis, FENOC assumed that the plant would feature a closed-cycle cooling system that would use mechanical-draft cooling towers. Cooling water intake, evaporative losses, and discharge flows for the plant would be less than one-third that of BVPS, primarily because only about one-third of its power would be derived from a steam cycle (see Table 7.2-1 and Sections 3.1.2 and 3.1.3).

The BVPS site would not be a viable location for the representative plant because there is insufficient area. Unused parts of the site, with exception of the SAPS area, consist almost entirely of very steep topography unsuited to development. The former SAPS site and adjacent land located on the Ohio River terrace immediately west (downstream) from the BVPS power block includes level terrain with reasonable potential for development. However, this area includes only approximately 14 acres situated between areas below the 100-year flood elevation and steep, forested slopes above the terrace, and offers a less than optimal configuration for a power plant (see Figure 2.1-3). FENOC estimates that a minimum of 10 acres would be required to accommodate just one of the dual-CT combined cycle units on the site. Considering also the highly congested nature of the present plant site and the potential for disruption of BVPS operations, FENOC assumed for the analysis that the representative gas-fired plant would be located elsewhere.

FENOC has not identified a specific site that would be suitable for the representative gas-fired plant. However, primary considerations for a cost-competitive site include proximity to adequate natural gas supply, transmission infrastructure, and cooling water, and sufficient land suitable for development. One potential option is location of the plant at a greenfield or, preferably, brownfield site similar to the BVPS site, within the major river corridors in the region (e.g., Ohio, Allegheny, Monongahela River corridors). However, as noted in the discussion of the coal-fired alternative (see Section 7.2.2.2), these river corridors are already substantially developed and the availability of a suitable site in 2016 is unknown. Moreover, FENOC notes that major natural gas pipelines are not located near these river corridors in many segments and could be relatively expensive to develop given the rugged topography of the area. A similar situation exists with respect to transmission lines; however, given the ability to transfer power in the RFC region, there would be considerable latitude in siting the facility in the region.

TABLE 7.2-1

REPRESENTATIVE NATURAL GAS-FIRED GENERATION ALTERNATIVE

Characteristic	Basis/Detail
No. of units, type and capability (net): 3 ea. GE S207FA @ 530 MW and 1 ea. GE S107FA @ 263 MW (Total = 1,853 MW)	Standard size approximately equivalent to BVPS total net capacity (vendor data).
Capability (gross): 7 ea CTs @ 171 MW, 3 ea. ST @ 196 MW, and 1 ea. ST @ 96 MW (Total = 1,881 MW).	Vendor data. Gross capability less net capability = energy consumed onsite.
Capacity factor: 80%	Within typical range of base-load plant; results in approximate annual output equal to or less than BVPS.
Fuel type = natural gas	Assumed.
Heat rate = 6,500 Btu/kWh	FENOC estimate from vendor data.
Fuel heating value = 1,025 Btu/ft^3	2000 value for Ohio natural gas receipts (Ref. 7.2-18, Table 14).
Fuel sulfur content: 0.2 grains/100 scf (= 0.00068 wt %)	Typical for pipeline quality natural gas (Ref. 7.2-19, Section 1.4.3).
SO_2 emissions: 0.00064 lb/MMBtu [= 0.94 x wt% sulfur in fuel]	EPA estimate for natural gas-fired turbines (Ref. 7.2-19, Table 3.1-2a).
NO_x emissions (assuming dry low-NO_x combustors): 0.099 lb/MMBtu	EPA estimate for best available NO_x combustion control (Ref. 7.2-19, Table 3.1-1).
NO_x post-combustion control: selective catalytic reduction (90% reduction)	EPA estimate for best available NO_x post-combustion control (Ref. 7.2-19, Section 3.1.4.3).
CO emissions (assuming dry low-NO_x combustors): 0.015 lb/MMBtu	EPA estimate (Ref. 7.2-19, Table 3.1-1).
PM emissions (all PM_{10}): 0.0019 lb/MMBtu	EPA estimate (Ref. 7.2-19, Table 3.1-2a).
CO_2 emissions: 110 lb/MMBtu	EPA estimate (Ref. 7.2-19, Table 3.1-2a).

% = percent
Btu = British thermal unit
BVPS = Beaver Valley Power Station
CO = carbon monoxide
CO_2 = carbon dioxide
CT = combustion turbine
EPA = U.S. Environmental Protection Agency
kWh = kilowatt-hour
lb = pound
MMBtu = million Btu
MW = megawatts
NO_x = nitrogen oxides
PM = filterable particulate matter
PM_{10} = filterable particulates with diameter less than 10 microns
Ref. = Reference
scf = standard cubic feet
SO_x = sulfur oxides
ST = steam turbine
wt% = percent by weight

Based on recent FirstEnergy experience in gas-fired plant siting, which resulted in new plant construction in northern Ohio and southeast Michigan, FENOC considered northwest Ohio to be a realistic general area in which to locate the facility. This area is attractive because it scores well in a variety of important criteria, particularly the likelihood of adequate gas supply, but also adequacy of transmission infrastructure, an abundance of available land that could be developed, and sufficient availability of water for cooling. Major interstate natural gas supply pipelines and related infrastructure are located in the area, including a major interconnection at Defiance, Ohio, fed from a major interstate hub (Sabine Pipeline, LLC's Henry Hub), and a hub at Maumee, Ohio. It is not certain this current infrastructure would be adequate to meet the needs of the representative plant in 2016 and 2027; however, it does offer the potential for upgrade and has existing rights-of-way for development of new pipelines. FENOC expects that electric transmission to Ohio load centers and in the RFC region to the south and east would be adequate. Favorable land use and socioeconomic factors FENOC considered in its gas-fired plant siting work include the fact that much of the land area in northwestern Ohio consists of cultivated farmland and scattered woodlots with low population density, yet Toledo, Ohio, Fort Wayne, Indiana, and other cities in the area would provide reasonable proximity to workforce and service infrastructure.

On the basis of the foregoing considerations, FENOC assumed for this analysis that the representative gas-fired plant would be located at a hypothetical greenfield site in northwestern Ohio, but acknowledges that sites may exist in areas nearer BVPS in Ohio, West Virginia, or Pennsylvania that would result in similar impacts. The plant also could be reasonably located at a brownfield site; however, as discussed in Section 7.3.2, impacts related to land use may reasonably be SMALL even at a greenfield site so this assumption does result in significant overestimation of impacts. FENOC further assumed that because the hypothetical plant would be sited in Ohio, environmental impacts associated with siting, design, and operation of the plant and associated new infrastructure (i.e., transmission lines, natural gas supply pipeline) would be subject to comprehensive review and approvals in accordance with Ohio Power Siting Board (OPSB) Rules [OAC Chapters 4906-1 through 4906-15]. These rules require a site selection study and comprehensive environmental impact review for all generating plants of 50 MW or more, transmission lines of 135 kV or more, and natural gas transmission lines operating at more than 125 pounds per square inch pressure.

FENOC estimates that a minimum of approximately 15 acres would be required to accommodate a single combined-cycle unit plant at a greenfield site, corresponding to approximately 60 acres for the fully developed four-unit representative plant. Up to approximately 15 additional acres per unit may be needed to achieve an effective site-specific facility configuration and accommodate construction laydown. Therefore, FENOC assumed a total area requirement of approximately 120 acres for the representative plant. Additional land for support infrastructure and buffer may be needed. For example, the NRC estimates that 110 acres would be required for a smaller (1,000-MW) plant (Ref. 7.0-1, Table 8.1).

Offsite infrastructure needed to locate the plant at a greenfield site is conjectural, but could reasonably include a natural gas supply pipeline, transmission line, and makeup water and discharge pipelines. The extent to which such infrastructure would be required is location-specific. For purposes of analysis, FENOC assumed that 10 miles of new natural gas pipeline would be needed to supply the plant, and that 10 miles of new 345-kV transmission line would be needed to connect the plant to the grid. FENOC assumed that the pipeline would require a right-of-way width of 75 feet and 50 feet for construction and operation, respectively, and that the transmission line would occupy a 150-foot-wide right-of-way.

FENOC assumed for this assessment that construction of the gas-fired units would be implemented as two projects timed to coincide with expiration dates of the BVPS licenses; i.e., a two-unit project to be completed in 2016 and a two-unit project to be completed in 2027. FENOC estimates that each of the projects could be constructed in 2 to 2.5 years with average and peak onsite workforces of approximately 500 and 900 workers, respectively. Operation of the completed four-unit plant is expected to require a permanent workforce of approximately 80 persons.

7.2.2.2 Representative Coal-Fired Generation

For purposes of this analysis, FENOC assumed development of a modern pulverized coal-fired power plant with state-of-the-art emission controls. The representative plant would consist of three commercially available standard-sized units, each with a nominal net output of approximately 600 MW, for a total net plant capacity of approximately 1,800 MW. This standard configuration would result in somewhat less generating capacity than BVPS' capacity of 1,842 MW, but is nonetheless comparable and, if anything, tends to result in underestimation of related impacts and thus provide conservatism in the alternatives analysis.

Table 7.2-2 lists basic specifications for the representative plant. Based on this information, annual coal consumption for the facility would be approximately 5.5 million tons, using the following calculation.

> Coal Combusted (tons/year) = Total Gross Capability (1,980 MW) x Heat Rate (9,800 Btu/kilowatt-hour) x 1,000 kilowatt/MW x 1/Fuel Heat Value (12,285 Btu/lb) x 0.0005 (ton/lb) x Capacity Factor (0.8) x 8,760 hr/year = 5.5 million tons/yr.

The facility would be designed to meet applicable standards with respect to control of air and wastewater emissions. As a minimum, FENOC assumed that the plant would feature low-nitrogen oxide burners with overfire air to minimize formation of nitrogen oxides, and selective catalytic reduction for post-combustion nitrogen oxide control. Emissions of particulate matter and mercury would be limited by use of a fabric filter (baghouse), and sulfur oxide emissions would be controlled using a wet scrubber using limestone as the reagent.

FENOC estimates that approximately 610,000 tons of limestone would be needed annually for scrubber operation. Exhaust would be dispersed through stacks approximately 500 feet high, assuming application of good engineering practice (40 CFR 51.100(ii)) on the basis of a boiler building height of approximately 200 feet.

FENOC estimates that the footprint for the generating facilities would minimally occupy 60 acres and that an additional 200 acres would be needed to accommodate related onsite infrastructure (e.g., fuel and limestone transport, storage, and handling; transmission; cooling water pipelines; cooling towers; administration; parking) for a total of 260 acres. Depending on location, additional land could be necessary to allow for a peripheral buffer. For example, the NRC estimates that 1,700 acres would be required for a smaller (1,000-MW) plant (Ref. 7.0-1, Table 8.1).

Additional land would be required to dispose of the substantial quantities of solid waste from the plant's air emissions control systems (i.e., ash and flue gas desulphurization waste). Although potential for recycling some of this material is likely to exist, FENOC is unable to predict the amount and assumed all of it would be landfilled. Assuming an average fill depth of 30 feet, approximately 1,400 acres would be required over an assumed 40-year plant life. Therefore, the minimum total land requirement for the plant is assumed to be approximately 1,660 acres.

The BVPS site would not be a viable location for the representative plant as a result of space limitations, as discussed in Section 7.2.2.1 with respect to the gas-fired alternative. Therefore, FENOC assumed for the analysis that the representative coal-fired plant would be located elsewhere. As noted above for the gas-fired plant, the ability to transfer power in the RFC region would provide latitude in siting the facility in the region. FirstEnergy has not conducted siting investigations for a coal-fired plant for many years and FENOC is not aware of any particular sites that would be suitable or available to accommodate development of the representative plant in 2016 and 2027. However, FENOC notes that a greenfield or (preferably) brownfield site close to a commercially navigable river (i.e., Ohio, lower Allegheny, or Monongahela Rivers) would be highly desirable if not essential from a technical and economic perspective, considering the relative abundance of cooling water and low fuel cost afforded by barge transportation of coal and limestone. Location on the river corridor would also be generally consistent with regional development, as evidenced by the many existing plants sited there (e.g., BVPS, Bruce Mansfield Plant, Sammis Plant) and by the highly industrialized nature of much of the river corridor (see Sections 2.1.2, 2.1.3). Development of the representative plant elsewhere in the region could entail construction of a cooling reservoir and new rail lines, with associated potential for additional environmental impacts not associated with a river corridor location.

In view of these considerations, FENOC assumed for purposes of this analysis that the representative plant would be located at a greenfield or brownfield site along commercially navigable portions of the Ohio, lower Allegheny, or Monongahela River corridors in the region. Based on FirstEnergy's experience, potentially viable locations for disposal of air emissions control waste from a plant located in the river corridor would be in uplands away from the river, as is the case for existing plants located there. For simplicity and comparability with the gas-fired alternative, FENOC also assumed that the environmental impacts associated with siting, design, and operation of the plant would be subject to comprehensive review under OPSB rules or a comparable process. As indicated by the analysis presented in Section 7.3.2, differences in impact between a greenfield and brownfield site at this level of analysis are small, particularly in view of other factors involved and the moderation imposed by OPSB or comparable regulatory review.

Consistent with the representative gas-fired plant alternative, FENOC assumed for this analysis that the representative coal-fired plant would use closed-cycle cooling with cooling towers. As with existing large steam-cycle power plants in the river valley, the use of natural draft cooling towers up to approximately 500 feet high is assumed. It is expected that cooling tower makeup, evaporative losses, and blowdown flows for the representative coal-fired plant would be somewhat lower than those described for BVPS in Section 3.1.3, considering its lower capacity rating (see Section 2.2.1.3) and the higher thermal efficiency of a coal-fired plant compared to a nuclear plant (Ref. 7.0-1, Table 8.2).

TABLE 7.2-2

REPRESENTATIVE COAL-FIRED GENERATION ALTERNATIVE

Characteristic	Basis/Detail
No. of units, type and capability (net): 3 ea. @ 600 MW (Total = 1,800 MW)	Standard size approximately equivalent to BVPS total net capacity (vendor data).
Capability (gross): 3 ea. @ 660 MW (Total = 1,980 MW)	Vendor data. Gross capability less net capability = energy consumed onsite.
Capacity factor: 80%	Within typical range of base-loaded plant, results in approximate annual generation comparable to or somewhat less than BVPS.
Firing mode: subcritical, tangential, dry-bottom pulverized coal	Widely demonstrated, reliable, economical; tangential firing minimizes NO_x emissions (Ref. 7.2-19, Table 1.1-3).
Fuel type: bituminous coal	Type used in FirstEnergy Ohio River plants.
Fuel heating value: 12,285 Btu/lb	Bruce Mansfield Plant average (Ref. 7.2-18, Table 24).
Heat rate: 9,800 Btu/kWh at full load	FirstEnergy experience.
Fuel ash content: 11.88 wt%	Bruce Mansfield Plant average (Ref. 7.2-18, Table 24).
Fuel sulfur content: 3.52 wt%; 2.86 lb/MMBtu	Bruce Mansfield Plant average (Ref. 7.2-18, Table 24).
Uncontrolled SO_x emissions: 130 lb/ton coal	EPA estimate calculated as 38 x wt% sulfur in coal (Ref. 7.2-19, Table 1.1-3).
Uncontrolled NO_x emissions: 10 lb/ton coal	EPA estimate (Ref. 7.2-19, Table 1.1-3).
Uncontrolled CO emissions: 0.5 lb/ton coal	EPA estimate (Ref. 7.2-19, Table 1.1-3).
Uncontrolled PM emissions: 120 lb/ton coal	EPA estimate calculated as 10 x wt% ash in coal (Ref. 7.2-19, Table 1.1-4).
Uncontrolled PM_{10} emissions: 27 lb/ton coal	EPA estimate calculated as 2.3 x wt% of ash in coal (Ref. 7.2-19, Table 1.1-4).
CO_2 emissions: 6,000 lb/ton coal	Approximate average for bituminous coal combustion (Ref. 7.2-19, Table 1.1-20).
NO_x control: low NO_x burners, overfire air, selective catalytic reduction (95% reduction)	Best available technology for minimizing NO_x emissions (Ref. 7.2-19, Table 1.1-2).
Particulate control: fabric filter (99.9% removal)	Best available technology for minimizing particulate emissions (Ref. 7.2-19, Section 1.1.4.1).
SO_x control: Wet limestone flue gas desulphurization (95% removal)	Best available technology for minimizing SO_x emissions (Ref. 7.2-19, Table 1.1-2).

% = percent
Btu = British thermal unit
BVPS = Beaver Valley Power Station
CO = carbon monoxide
EPA = U.S. Environmental Protection Agency
kWh = kilowatt-hour
lb = pound
MMBtu = million Btu
MW = megawatts
NO_x = nitrogen oxides
PM = filterable particulate matter
PM_{10} = filterable particulates with diameter less than 10 microns
Ref. = Reference
SO_x = sulfur oxides
wt% = percent by weight

Offsite infrastructure needed for the representative plant is conjectural, but would most likely include transmission lines as needed to connect the plant to the grid. For purposes of analysis, FENOC assumed that 10 miles of new 345-kV transmission line would be needed and that it would occupy a 150-foot-wide right-of-way.

As with the gas-fired option, FENOC assumed for this assessment that construction of the coal-fired units would be implemented in stages. For purposes of analysis, two projects timed to coincide with expiration dates of the BVPS licenses; i.e., a one-unit or two-unit project to be completed in 2016 and a one-unit or two-unit project to be completed in 2027. FENOC estimates that a single unit could be constructed in approximately 3 years and two units could be constructed in approximately 4 years, with average and peak onsite workforces of approximately 1,750 and 2,500 workers, respectively. A permanent workforce of approximately 300 persons would be required to operate the completed three-unit facility.

7.2.3 Other Alternatives Considered

In this section, FENOC describes alternatives other than purchasing power and developing new coal- or natural gas-fired generation that were considered. The discussion includes the reasons why FENOC does not consider these alternatives to be reasonable or feasible for purposes of this evaluation.

7.2.3.1 Other Generation Alternatives

In addition to coal-fired and natural gas-fired generation, representative examples of which are identified as feasible alternatives in Section 7.2.2, the NRC evaluated several other generation technologies in the GEIS (Ref. 7.0-1, Chapter 8.0). FENOC has considered these options as potential alternatives to continued operation of BVPS and determined them to be unreasonable on the basis of economics, high land-use impacts, low capacity factors, geographic limitations, insufficiently developed technology, or other reasons. Table 7.2-3 summarizes the results of the review.

7.2.3.2 Purchased Power

Each of the states (Ohio, Pennsylvania, and New Jersey) in which FirstEnergy serves load have undertaken electric industry restructuring initiatives that promote competition in retail energy markets by allowing participation of non-utility suppliers. Retail customers historically served by the regulated operating subsidiaries of FirstEnergy now have the option to choose between FirstEnergy-affiliated suppliers and other state-qualified energy suppliers.

However, projections for the RFC region, which includes the former ECAR and MAAC regions, indicate that additional generating capacity would be needed in the region in order to maintain sufficient capacity reserves beyond 2012 (4 years prior to expiration of the current operating license for BVPS-1). The amount of capacity needed to maintain a 15-percent reserve margin ranges from 1,600 MW in 2013 to 8,400 MW in 2015 (Ref. 7.2-16). Considering these capacity needs with all new announced generation projects and planned retirements, there is the potential for a capacity shortage in the region even with the continued operation of both BVPS units. Taking one or both of the BVPS units would deepen concerns over a potential energy shortfall, at the least, or result in or worsen an energy shortage, at the most. Therefore, FENOC has determined that purchased power would not be a reasonable alternative to replace power lost in the event the BVPS operating licenses are not renewed.

7.2.3.3 Delayed Retirement of Existing Non-Nuclear Units

Extending the lives of existing non-nuclear generating plants beyond the time they were originally scheduled to be retired represents another potential alternative to license renewal (Ref. 7.0-1, Section 8.3.13). However, this does not represent a realistic option with respect to FirstEnergy's generating assets, and FENOC is not knowledgeable of retirement plans of other regional electric power suppliers. Even without retiring any generating units, FirstEnergy expects to require additional capacity in the near future.

Therefore, even if a substantial portion of its capacity were scheduled for retirement and could be delayed, some of the delayed retirement would be needed just to meet load growth.

In addition, FirstEnergy does not have conceptual retirement plans that extend out to the potential license expiration time for BVPS units (2016 to 2027). However, such plans likely would be driven largely by environmental regulations and associated economics. As indicated in Section 7.2.1.2, approximately 54.8 percent of FirstEnergy's generating capacity consists of coal-fired plants which, due to a lower cost of generation, are used at capacity factors higher than other fossil-fuel generating units. Virtually all of FirstEnergy's non-nuclear base-load generating capability is from coal firing. These coal-fired plants, which were developed in the 1980s or earlier, represent the only plants in FirstEnergy's portfolio that would have any potential for continued operation to replace the substantial amount of base-load generation represented by BVPS. However, older plants that do become candidates for retirement generally represent less efficient generation and pollution control technologies than are available in more modern plants, and continued operation typically would require substantial upgrades to be economically competitive and meet applicable environmental standards. In many cases, it is likely that such upgrades would not be economically viable. In any event, FENOC expects that the environmental impacts of implementing such upgrades and operating the upgraded plants are reasonably bounded by assessments presented in this chapter for the gas-fired and coal-fired alternatives.

TABLE 7.2-3

OTHER GENERATION TECHNOLOGY OPTIONS CONSIDERED

Alternative	Considerations/Reasons for Not Evaluating Further[a]
Wind	Intermittency of adequate wind speed and expense of energy storage results in capacity factors too low for base-load generation, and land requirements would be very large for the 1,842 MW required to replace BVPS (Ref. 7.0-1, Section 8.3.1). In 2004, approximately 150 and 70 MW of wind-power generating capacity has been developed in ECAR and MAAC, respectively. The DOE-EIA projects that by 2030, approximately 800 MW and 30 MW of additional wind-power generating capacity will be developed in ECAR and MAAC, respectively (Ref. 7.2-11, Tables 76 and 78). According to the *Wind Energy Resource Atlas of the United States* (Ref. 7.2-20), areas suitable for wind energy applications must be wind-power Class 3 or higher. Coastal regions along Lake Erie in northwestern Ohio have an estimated wind power of Class 3, increasing to Class 5 over offshore areas. The rest of the state, however, is devoid of Class 3 or higher wind-power areas. Approximately 50 percent of the land area in Pennsylvania and West Virginia has a wind-power classification of 3 or higher and, therefore, may be suitable for wind-energy applications. However, many of the wind-power Class 3 areas are located in the Appalachian Mountains, where, due to the steep topography, high wind resource capability only exists on a small fraction (1 to 20 percent) of those areas. From a practical perspective, the scale of this technology is too small to directly replace a power generating plant the size of BVPS, and the functionality is not equivalent.
Solar Photovoltaic and Solar Central Receiver	The DOE-EIA indicates that currently there is no commercial solar-thermal or solar-photovoltaic generating capability in either ECAR or MAAC. The DOE-EIA does not anticipate that commercial solar generating capacity will be developed in either ECAR or MAAC (Ref. 7.2-11, Tables 76 and 78). As the NRC notes in the GEIS, low solar resource availability in the region (e.g., less than 3.3 kWh/m^2 per day in Ohio, western Pennsylvania, and northern West Virginia; less than half of that available in the southwestern United States), intermittency of this resource, and expense of energy storage results in capacity factors too low for practical base-line generation. Land requirements are very large. Based on estimates presented in the GEIS, approximately 26,000 acres and 64,000 acres, respectively, would be required for 1,842 MW of solar-thermal or solar-photovoltaic generating capability to replace BVPS, even in areas of high solar availability (Ref. 7.0-1, Sections 8.3.2, 8.3.3). Because of the area's low rate of solar radiation and high technology costs, solar power in the region is limited to niche applications and is not a feasible base-load alternative to BVPS license renewal.
Hydroelectric	According to the DOE (Ref. 7.2-21; Ref. 7.2-22; Ref. 7.2-23), a combined total of approximately 2,000 MW to 4,300 MW of undeveloped hydropower potential exists in Ohio, West Virginia, and Pennsylvania. However, as noted in the GEIS, hydroelectric power's percentage of the country's generating capacity is expected to decline due to the relatively low capacity factor, large land-use requirement (e.g., inundation of approximately 1.8 million acres for a hydroelectric plant large enough to replace BVPS), and ecological impacts during operation (e.g., fish impingement, entrainment) (Ref. 7.0-1, Section 8.3.4). In 2004, approximately 1,180 and 1,220 MW of hydropower generating capacity had been developed in ECAR and MAAC, respectively. The DOE-EIA projects that no additional hydroelectric generating capacity will be developed in either ECAR or MAAC (Ref. 7.2-11, Tables 76 and 78).

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

Alternative	Considerations/Reasons for Not Evaluating Further[a]
Geothermal	As noted in the GEIS, hydrothermal reservoirs in the United States are most prevalent in contiguous western states, Alaska, and Hawaii and are limited in the northeastern United States (Ref. 7.0-1, Section 8.3.5). Currently, there is no geothermal generating capability in the region, nor does the DOE-EIA anticipate that any additional generating capability will be developed in either ECAR or MAAC through 2030. (Ref. 7.2-11, Tables 76 and 78).
Biomass	Biomass alternatives, including wood- and crop-fired plants, have construction-related environmental impacts similar to coal-fired plants, requiring large areas for fuel storage, processing, and waste disposal. As noted in the GEIS, a significant barrier to the use of wood waste to generate electricity is the high delivered-fuel cost and high construction cost per MW of generating capacity. The maximum capacity for wood-waste power plants is between 40 to 50 MW. Additionally, large-scale timber cutting can result in significant ecological impacts (e.g., soil erosion and loss of wildlife habitat). Other biomass alternatives, including burning crops, converting crops to a liquid fuel such as ethanol, and gasifying crops, have not progressed to the point of being competitive on a large scale or of being reliable enough to replace a base-load plant such as BVPS (Ref. 7.0-1, Sections 8.3.6 and 8.3.8) The DOE estimates that potentially over 40 billion kWh of electricity could be generated from biomass fuels in Pennsylvania, Ohio, and West Virginia (Ref. 7.2-24; Ref. 7.2-29; Ref. 7.2-30). However, as pointed out above, the economic and achievable potential is almost certain to be substantially less than the technical potential. In 2004, ECAR and MAAC had approximately 170 and 30 MW of biomass generating capacity, respectively. The DOE-EIA projects that by 2030 an additional 110 MW of biomass generating capacity will be developed in MAAC. The DOE-EIA did not project additional generating capacity for ECAR (Ref. 7.2-11, Tables 76 and 78).
Municipal Solid Waste	Installed capital cost of a municipal solid-waste-fueled plant is higher than that of a wood-waste-fueled plant (Ref. 7.0-1, Section 8.3.7). Use of this option is primarily a waste management decision. Tipping fees, availability of landfill space, and reduced heat content of the waste stream due to segregation and recycling of high-heat-content components (e.g., wood, paper, plastics) affect economic viability. In 2004, approximately 170 and 660 MW of municipal solid waste generating capacity was available in ECAR and MAAC, respectively. The DOE-EIA projects that by 2030 an additional 50 and 80 MW of municipal solid waste generating capacity will be developed in the respective ECAR and MAAC regions (Ref. 7.2-11, Tables 76 and 78).
Oil	FirstEnergy has several small oil-fired units; however, they produce a negligible amount of FirstEnergy's power generation. The cost of oil-fired operation is more expensive than nuclear or coal-fired operation. In addition, future increases in oil prices are expected to make oil-fired generation increasingly more expensive than coal-fired generation. The high cost of oil has prompted a steady decline in its use for electricity generation. The DOE-EIA estimates that the total generation from oil in ECAR and MAAC will respectively decrease from 5.71 billion kWh and 9.41 billion kWh in 2004 to 4.3 billion kWh and 7.67 billion kWh in 2030 (Ref. 7.2-11, Table 74).

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

Alternative	Considerations/Reasons for Not Evaluating Further[a]
Advanced Nuclear Reactor	Increased interest in the development of advanced reactor technology has been expressed recently by members of both industry and government. However, FirstEnergy has not developed plans to construct a new nuclear power plant; and considers it unlikely that a site for a new nuclear facility could be identified/acquired, and replacement for BVPS could be planned, licensed, constructed, and on line by the time the Unit 1 operating license expires. Moreover, the economics of new nuclear plants remain uncertain with escalating fuel and construction costs emerging as negative forces which could affect the viability of this option. Operation of an advanced reactor would have environmental impacts similar to those of the continued operation of BVPS, and construction of a new nuclear power plant would entail further environmental impacts and incur capital costs not associated with license renewal of BVPS. For these reasons, FENOC does not consider development of a new nuclear plant to be a preferable alternative to BVPS license renewal at this time.
Fuel Cells	Cost is the primary hurdle to fuel-cell development as a major generating source Capital costs for fuel cell installations range from $2,800 to $5,500 per kilowatt. Recent estimates suggest that manufacturers would need to at least triple their production capacity to achieve a competitive price of $1,500 to $2,000 per kilowatt (Ref. 7.2-25). FENOC believes fuel cells are not currently economically or technologically competitive with other alternatives for base-load electricity generation.

[a]Current and projected capacity data from DOE-EIA (Ref. 7.2-11) cited in this table do not include small onsite sources of power, some of which may supply excess capacity to the grid. However, the amount of such capacity is very small in both 2004 and 2030, and does not affect the rationale presented.

BVPS = Beaver Valley Power Station
DOE = U.S. Department of Energy
ECAR = East Central Area Reliability Coordination Agreement
FENOC = FirstEnergy Nuclear Operating Company
GEIS = *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*
kWh = kilowatt hour(s)
m^2 = square meter(s)
MAAC = Mid-Atlantic Area Council
MW = megawatt(s)
NRC = U.S. Nuclear Regulatory Commission
Ref. = Reference

7.2.3.4 Conservation

There is a wide variety of conservation technologies (e.g., DSM) that could be considered as potential alternatives to generating electricity at BVPS. Examples of these conservation options include:

- Conservation Programs—homeowner agreements to limit energy consumption; educational programs that encourage the wise use of electricity.
- Energy Efficiency Programs—discounted residential rates for homes that meet specific energy efficiency standards; programs providing residential energy audits and encouraging

efficiency upgrades; incentive programs used to encourage customers to replace older inefficient appliances or equipment with newer versions that are more efficient.

- Load Management Programs—programs that encourage customers to switch load to customer-owned standby generators during periods of peak demand; programs that encourage customers to allow a portion of their load to be interrupted during periods of peak demand.

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

- Increasing long-term marginal prices for capacity and energy production resources;
- Forecasts projecting increasing demand for electricity across the nation;
- General agreement that increasing pricing and demand would continue for the foreseeable future;
- Limited competition in the generation of electricity;
- Economies of scale in the generation of electricity, which supported the construction of large central power plants; and
- Use of average embedded cost as the basis for setting electricity prices within a regulated context.

As noted in Section 7.2.1.1, these market and regulatory conditions are undergoing dramatic changes that have significantly affected the cost-effectiveness of utility-sponsored DSM. Among the factors most responsible are a decline in generation costs, due primarily to technological advances that have reduced the cost of constructing new generating units, particularly combustion turbines and combined-cycle units, and national energy legislation that has encouraged wholesale competition through open access to the transmission grid, as well as state legislation designed to facilitate retail competition. Other significant changes include the adoption of increasingly stringent national appliance standards for most major energy-using equipment and the adoption of energy efficiency requirements in state building codes. These mandates have further reduced the potential for cost-effective utility-sponsored measures. Finally, energy services and products are increasingly being offered in competitive markets at prices that reflect their value to the customer. Market conditions can be expected to continue this shift among providers of cost-effective load management.

In the past, FirstEnergy had a variety of DSM programs offered to residential, commercial, and industrial customers. However, these programs were largely discontinued due to the implementation of retail competition. FirstEnergy does maintain an interruptible load program. The forecast for the amount of interruptible load available to FirstEnergy operating companies serving Ohio is in a fairly consistent range of 470 to 500 MW over the 2003 – 2012 forecast period. This interruptible load is included as an important factor in FirstEnergy's calculations of resource supply adequacy. RFC considers interruptible loads to be supplemental capacity resources, but does reflect the effects of non-controlled DSM in its internal demand forecast (Ref. 7.2-16). Because DSM is already incorporated into supply planning, it does not represent a meaningful alternative to renewal of the BVPS operating licenses.

7.3 ENVIRONMENTAL IMPACTS OF ALTERNATIVES

FENOC's evaluations of environmental impacts for the feasible replacement power alternatives are presented in the following sections. Sections 7.3.1 and 7.3.2, respectively, address impacts associated with the natural gas-fired and coal-fired representative alternatives. The evaluations focus on the impacts specific to these alternatives. Impacts associated with terminating operations and decommissioning BVPS (i.e., base case, Section 7.1.1) are expected to be of small significance for all resource areas addressed except socioeconomics; therefore, these generally are not further discussed. However, conclusions expressed below regarding the significance of impact for each alternative denote the total expected impact for each resource area, inclusive of the base case. The influence of the base case on these conclusions is noted where appropriate.

The new generating plants addressed in Sections 7.3.1 and 7.3.2 would not be constructed only to operate for the period of extended operation of BVPS. Therefore, FENOC assumes for this analysis a typical design life of 30 years for the combined-cycle natural gas-fired plant and 40 years for the coal-fired plant and considers impacts associated with operation for the entire design life of the units in this analysis. As discussed in Section 7.2, FENOC assumed that construction of these plants would be phased to provide replacement capacity in 2016 and 2027 when the respective operating licenses for BVPS-1 and BVPS-2 expire.

Chapter 8 presents a summary comparison of the environmental impacts of license renewal and the alternatives discussed in this section.

7.3.1 Gas-Fired Generation

Potential impacts associated with FENOC's natural gas-fired representative alternative, as described in Section 7.2.2.1, are addressed in the following subsections by resource category. As indicated in Section 7.2.2.1, FENOC assumed for the analysis that the representative gas-fired plant would be located at a hypothetical greenfield site in northwestern Ohio.

Land Use
Development of the representative combined-cycle natural gas-fired plant would require approximately 120 acres for the plant site. Assuming 10 miles each of 345-kV transmission line on a 150-foot right-of-way and natural gas supply pipeline on a 50-foot right-of-way (75-foot during construction), approximately 240 – 270 additional acres would be needed offsite. Potential impacts on land use would be location-specific. Land use in northwestern Ohio is predominantly rural agricultural cropland with scattered rural residences and woodlots. Located in a rural area, the change in land use would be locally apparent and could include displacement of cropland, which is highly productive for corn, wheat, and soybeans relative to other areas of the state (Ref. 7.2-26); however, substantial buffer with respect to highly incompatible land uses (e.g., residential use) could be provided and destabilization of overall land use would not be expected. If the plant were located in an area designated for industrial use, associated land-use impacts would not be significant. Agricultural practices could continue along most of the area occupied by offsite rights-of-way. Considering also that land use impacts would be addressed in siting and design of these facilities under OPSB rules, FENOC concludes that land-use impacts would range from SMALL to MODERATE, depending on site-specific factors.

Water Use and Quality

As noted in Section 7.2.2.1, cooling water intake, evaporative losses, and discharge flows for the plant would be much less than those resulting from BVPS operation, which provides some flexibility to locate and design the unit to lessen potential for impact on water use and quality. Moreover, cooling water and wastewater discharges would be regulated under the federal CWA and corresponding state programs by an NPDES permit. Construction activities would be similarly regulated to ensure protection of water resources. In addition, impacts on water use and quality would be subject to scrutiny in the planning stage under OPSB or current governing authority rules. Therefore, FENOC concludes that impact on water use and quality for the representative plant likely would be SMALL.

Air Quality

Potential for adverse impacts to air quality from a fossil-fueled power plant are substantially different from those of a nuclear power plant. The combustion process results in emissions of criteria pollutants including nitrogen oxides, sulfur dioxide, carbon monoxide, and particulates, as well as carbon dioxide, an unregulated "greenhouse gas" implicated as a potential contributor to climate change. However, natural gas contains very little sulfur and other contaminants that are present in coal and oil and is inherently a relatively clean-burning fossil fuel. As a result, emissions of most pollutants would be generally much lower than for a comparably sized coal-fired plant.

As Section 7.2.2.1 indicates, FENOC has assumed a plant design that includes controls to effectively minimize emissions of regulated air pollutants. Based on emission factors and estimated efficiencies for emission controls cited by the EPA and assumed design parameters as listed in Table 7.2-1, operation of the plant would result in the following annual air emissions for criteria pollutants: sulfur dioxide = 27 tons, nitrogen oxides = 424 tons, carbon monoxide = 643 tons, and total filterable particulates (all PM_{10}) = 81 tons. Annual emissions of regulated air pollutants were calculated as follows from natural gas heat input and EPA estimates of uncontrolled air emissions and removal efficiencies (Table 7.2-2 and Section 7.2.2.1 list all necessary parameters and values), assuming that removal efficiencies for SOx, CO, and filterable particulates are zero.

> Annual Emissions (tons/yr) = Natural Gas Heat Input (85,680,000 MMBtu/yr) x Uncontrolled Emissions (lb/MMBtu) x 0.0005 (ton/lb) x [100 – removal efficiency (%)].

On this same basis, annual emissions of carbon dioxide, which is currently unregulated, would be approximately 4.7 million tons. The regulated pollutants sulfur dioxide, nitrogen oxides, particulates, and carbon monoxide are of concern from a human health perspective; sulfur dioxide and nitrogen oxides are contributors to acid rain; and carbon dioxide has been identified as a potential contributor to climate change (Ref. 7.0-1, Section 8.3.9).

These emissions may result in a noticeable reduction in local air quality. However, both sulfur dioxide and nitrogen oxide emissions from regional power plants are subject to cap and trade programs such as that described for Ohio in Section 7.2.1.3, and allowances or offsets would have to be obtained as needed to reconcile emission budgets for these pollutants. As a result of these programs, the plant would not be expected to add to regional sulfur dioxide emissions and, depending on the status of available nitrogen oxide budget allocations, the plant also may not add to regional nitrogen oxide emissions, at least during the ozone season. The representative plant would add to regional concentrations of other pollutants, including the criteria pollutants carbon monoxide and particulates, and carbon dioxide, which is unregulated. However, considering that the plant would be subject to regulatory controls, FENOC concludes that the overall impact on air quality from this alternative would be noticeable but not destabilizing, a characteristic of MODERATE impact.

Waste Management
Operation of the gas-fired alternative would generate small quantities of waste, primarily consisting of municipal and industrial waste, which would be disposed of in accordance with applicable regulations at a permitted disposal facility. FENOC concludes that the gas-fired generation waste management disposal impacts would be SMALL.

Ecological Resources
As noted above, development of the representative combined-cycle natural gas-fired plant may require approximately 120 acres for the plant site and approximately 240 – 270 additional acres for offsite infrastructure. The type and quality of terrestrial habitat that would be displaced is location-specific. However, FENOC considers it likely that most of the area required would consist of agricultural cropland with relatively low habitat value. Stream crossings and wetland disturbance, if any, would be subject to provisions of a USACE permit (CWA Section 404) and relevant state and local requirements.

The most significant potential impacts to aquatic communities relate to operation of the cooling water system. However, the cooling system for the plant would be designed and operated in compliance with the CWA, including NPDES limitations for physical and chemical parameters of potential concern and provisions of CWA Sections 316(a) and 316(b), which are respectively established to ensure appropriate protection of aquatic communities from thermal discharges and cooling water intakes.

Considering the quantity and quality of habitat likely to be displaced by the plant and associated offsite infrastructure, mitigation available to replace wetland values lost, and assumed environmental protections that would be afforded in siting, design, and operation of these facilities under OPSB rules, FENOC expects that development of the representative natural gas-fired plant would likely have little noticeable impact on ecological resources of the area, a characteristic of SMALL impact.

Socioeconomics
Major sources of potential socioeconomic impacts from the representative gas-fired generation alternative include

- Temporary increases in jobs, economic activity, and demand for housing and public services in communities surrounding the site during the construction period; and
- Loss of permanent jobs, tax revenues, and economic activity attributable to gas-fired plant operation and termination of operations of the BVPS units.

As discussed in Section 7.2.2.1, FENOC assumed that construction of the representative gas-fired alternative at a greenfield site in northwestern Ohio would be implemented as two projects timed to coincide with expiration dates of the BVPS operating licenses in 2016 and 2027, respectively. Each project would be constructed in approximately 2 to 2.5 years and would employ average and peak onsite construction workforces of approximately 500 and 900 workers, respectively. Operation of the four-unit plant would require a permanent workforce of 80 persons.

Although northwestern Ohio is predominantly rural, most areas are within commuting distance of the MSAs of Fort Wayne, Indiana, Toledo, Ohio, and Lima, Ohio, which have populations ranging from approximately 155,000 to 618,000 based on 2000 census data (Ref. 7.2-27). Considering the proximity of these sources of labor and services, FENOC expects that most of the construction workforce would commute and relatively few would relocate into the area, and associated socioeconomic impacts during construction would be SMALL.

However, communities in Beaver County, particularly those within the taxing jurisdiction of the South Side Area School District, would experience losses in both employment and tax revenues due to BVPS closure that could constitute MODERATE impact (see Section 7.1.1). Therefore, FENOC concludes that overall socioeconomic impacts of the gas-fired alternative would be MODERATE due to the noticeable but not destabilizing effects of BVPS closure on communities in Beaver County.

Human Health
In the GEIS, the NRC cites risk of accidents to workers and public health risks (e.g., cancer, emphysema) from the inhalation of toxics and particulates associated with air emissions as potential risks to human health associated with the gas-fired generation alternative (Ref. 7.0-1, Table 8.2). FENOC assumed that regulatory requirements imposed on facility design, construction, and operations under the authority of the *Occupational Safety and Health Act*, *Clean Air Act*, and related statutes are designed to provide an appropriate level of protection to workers and the public, and that compliance with those requirements would result in SMALL, if any, impacts on human health, regardless of plant location.

Aesthetics
Potential aesthetic impacts of construction and operation of a gas-fired plant include visual impairment resulting from the presence of a large industrial facility, including a building housing the CTs and HRSGs, multiple exhaust stacks at least 150 feet high, and mechanical-draft cooling towers, with associated condensate plumes. Considering the flat topography in northwestern Ohio, the stacks and condensate plumes would likely be visible for several miles from the site; new transmission lines constructed to connect the plant to the grid would also be relatively visible for the same reason, though would not be out of character for the rural northwestern Ohio landscape. FENOC expects that the plant likely would be located in a rural area, and assumed that adequate buffer and vegetation screens would be provided at the plant site as needed to moderate visual and noise impacts. Considering also that the location and design of the plant and associated offsite infrastructure would be subject to review under OPSB rules, FENOC concludes that aesthetic impact could range from SMALL to MODERATE, depending on location.

Cultural Resources
FENOC assumed that the representative gas-fired plant and associated gas-supply pipeline and transmission line would be located with consideration of cultural resources under OPSB or comparable program rules, and that appropriate measures would be taken to avoid, recover, or provide other mitigation for loss of any resources discovered during onsite or offsite

construction. On this basis, FENOC concludes that the potential adverse impact on cultural resources from this alternative would likely be SMALL.

7.3.2 Coal-Fired Generation

FENOC presents its impact evaluations for the representative coal-fired generation alternative in the following subsections by resource category. As discussed in Section 7.2.2.2, FENOC assumed for purposes of this analysis that the representative plant would be located at a greenfield or brownfield site along commercially navigable portions of the Ohio, lower Allegheny, or Monongahela River corridors in the region.

Land Use
Development of the representative coal-fired plant would require approximately 260 acres for the generating and related support facilities and as much as 1,400 acres of additional land for disposal of air emissions control waste. Assuming 10 miles of 345-kV transmission line on a 150-foot right-of-way is needed to connect the plant to the grid; approximately 180 additional acres would be needed offsite. Potential impacts on land use would be location-specific. However, to be cost effective, it is likely that plant facilities would be located on a river terrace, as is the case for BVPS and many other large power plants in the region, including FirstEnergy's Bruce Mansfield and W.H. Sammis Power Plants (see Section 2.1.2). With few exceptions, these sites are already largely developed, and are often proximate to residential areas, presenting potential for at least moderate land-use impacts, except for formerly used industrial sites, if available, to accommodate power plant development in 2016 and 2027. Potential for land-use conflicts would exist in otherwise viable sites along the river, regardless of current status of development, if they were located within the 100-year floodplain. These sites would minimally require demonstration that development would not unacceptably restrict flood flows and would be appropriately viewed as having at least MODERATE land-use impact.

As noted in Section 7.2.2.2, the air emissions control waste is assumed to be located in uplands away from the river. Considering the generally rugged topography of these uplands, predominant land use and vegetation cover in the area, and practices at other coal-fired plants in the region, potentially suitable disposal sites could include valley fills in areas now forested or reclaimed subsequent to coal mining. Considering the large land area requirement (up to 1,400 acres), the waste disposal site would likely result in displacement of some rural residential land use or present similar land-use conflicts. Resulting impacts would be clearly noticeable, and substantial conflicts with existing land use could result at some locations.

FENOC expects that the 10 miles of new transmission line assumed for the plant could be installed and operated with SMALL to MODERATE land-use impact.

FENOC assumed for this analysis that the land-use impacts related to the location, design, and operation of the plant, waste disposal site, and other offsite infrastructure would be subject to regulatory review under OPSB or comparable program rules or similar programs. FENOC assumed that this review process, including application of appropriate mitigation found to be needed as a result, would ensure that impacts on land use, such as those discussed, would not be destabilizing. On this basis, FENOC concludes that land-use impacts would be MODERATE.

Water Use and Quality
Construction-phase impacts on water quality of greatest potential concern include erosion and sedimentation associated with land clearing and grading operations at the plant site and waste disposal site, and suspension of bottom sediments during construction of cooling water intake and discharge structures and facilities for barge delivery of coal and limestone. However, land clearing and grading activities would be subject to stormwater protections in accordance with the NPDES program, and work in waterways would be regulated by the USACE under the CWA Section 404 and Section 10 of the *Rivers and Harbors Act*; these activities would also be subject to corresponding state and local regulatory controls, as applicable. In addition, these adverse effects would be localized and temporary. FENOC concludes that impacts on surface water quality associated with construction of the representative plant would be SMALL.

FENOC expects that potential impacts on water quality and use associated with operation of the representative plant would be similar to impacts associated with BVPS operation. Cooling water and other wastewater discharges would be regulated by an NPDES permit, regardless of location. Cooling water intake, evaporative losses, and discharge flows for the representative coal-fired plant, assumed to use a closed-cycle cooling system, would be similar to or lower than those resulting from BVPS operation, which results in SMALL impacts (see Section 3.1.3 and Chapter 4).

Considering also the environmental review of water use and quality issues afforded under OPSB rules or a similar program, FENOC concludes that the impacts of surface water use and quality from construction and operation of the representative plant would be SMALL.

Air Quality
The principal air emissions from a coal-fired power plant are the same as those noted in Section 7.3.2 for the natural gas alternative and are of concern for the same reasons. However, coal contains much higher concentrations of sulfur, and combustion is less efficient than for natural gas. As a result, even with application of appropriate control technologies, emission of these pollutants from a coal-fired facility are typically substantially higher than for a natural gas-fired facility of comparable size. In addition, coal contains other constituents (e.g., mercury, beryllium) that are potentially emitted as hazardous air pollutants, which are also of concern from a human health standpoint (Ref. 7.0-1, Section 8.3.9).

As Section 7.2.2.2 indicates, FENOC has assumed a plant design that includes controls to effectively minimize emissions of regulated air pollutants. Based on emission factors and estimated efficiencies for emission controls cited by the EPA and assumed design parameters listed in Table 7.2-2, operation of the plant would result in the following annual air emissions for criteria pollutants: sulfur dioxide = 18,000 tons, nitrogen oxides = 1,400 tons, carbon monoxide = 1,400 tons, total filterable particulates = 330 tons, and PM_{10} = 74 tons. On this same basis, annual emissions of carbon dioxide, which is currently unregulated, would be approximately 16.5 million tons. Annual emissions of regulated air pollutants were calculated as follows from amount of coal combusted and EPA estimates of uncontrolled air emissions and removal efficiencies (all necessary parameters and values are listed in Table 7.2-2).

Pollutant Emissions (tons/yr) = Coal Combusted (5.5 million tons/yr) x Uncontrolled Emissions (lb/ton) x 0.0005 (ton/lb) x [100 – removal efficiency

(%)]. Removal efficiency for carbon monoxide and carbon dioxide are assumed to be zero percent.

FENOC expects that these emissions would result in a noticeable reduction in local air quality. However, as for the gas-fired alternative, both sulfur dioxide and nitrogen oxide emissions from regional power plants are subject to cap and trade programs such as those described for Ohio in Section 7.2.1.3, and allowances or offsets would have to be obtained as needed to reconcile emission budgets for these pollutants. As a result of these programs, the plant would not be expected to add to regional sulfur dioxide emissions and, depending on the status of available nitrogen oxide budget allocations, the plant also may not add to regional nitrogen oxide emissions, at least during the ozone season. The representative plant would add to regional concentrations of other pollutants, including the criteria pollutants carbon monoxide and particulates; hazardous air pollutants such as mercury; and carbon dioxide, which is unregulated. However, considering that the plant would be subject to regulatory controls, FENOC concludes that the overall impact on air quality from this alternative would be noticeable but not destabilizing, a characteristic of MODERATE impact.

Waste Management
The representative coal-fired plant would annually consume approximately 5.5 million tons of coal, having an ash and sulfur content of 11.88 percent and 3.52 percent, respectively. FENOC assumed air emission controls would remove 99.9 percent of the ash and 95 percent of the sulfur (see Table 7.2-1), reducing estimated annual waste generation amounts to approximately 650,000 tons/year of ash and 1,022,000 tons of flue gas desulphurization waste (dry basis), consisting primarily of hydrated calcium sulfate (gypsum) and excess limestone reactant. These wastes represent potentially usable products. However, considering the relatively large volume of this material and uncertainties in future demand, FENOC has assumed the total waste generated would be disposed of at an offsite landfill (see Section 7.2.2.2). Assuming a fill depth of 30 feet, approximately 1,400 acres would be required for the landfill over an assumed plant operating life of 40 years.

FENOC assumed that the air pollution control waste landfill would be designed and operated to maintain landfill integrity and minimize the potential for escape of leachate (e.g., impermeable liner, leachate collection system) in accordance with OAC 3745-30 (if the plant is located in Ohio) or comparable regulations to minimize potential for local degradation of groundwater quality. FENOC assumed that groundwater quality degradation, in the event it did occur, would be appropriately managed to ensure potential uses remain protected. After closure and revegetation of the disposal facility, the land could be made available for other noninvasive uses (e.g., recreation).

Because the ash disposal landfill is assumed to be located offsite, the air pollution control waste would have to be transported from the plant site. FENOC considers that truck transport would most likely be used. Related operational impacts would depend to a large extent on the extent to which public roads are used and land use along the haul route.

Under the assumptions of this analysis, environmental impacts related to the location, design, and operational aspects of waste disposal for the plant would be subject to regulatory review under OPSB rules or similar programs. FENOC assumed that this review process, including application of appropriate mitigation found to be needed as a result, would ensure that impacts such as those discussed would not be destabilizing. On this basis, FENOC concludes that waste management impacts would be MODERATE.

Ecological Resources

As indicated in the land-use impact discussion above, development of the representative coal-fired plant would require approximately 260 acres for a plant site, likely located along the river, and as much as 1,400 acres for waste disposal, which FENOC assumes would be located in upland areas away from the river, and 180 acres for transmission line right-of-way. The type and quality of terrestrial habitat that would be displaced is location-specific. However, most areas along the river potentially suitable for a plant site are already largely developed and would be expected to have low habitat values for wildlife. Potentially developable areas along the river that are not already so are more likely to be within the 100-year floodplain and subject to less intensive uses and could include some wetland areas, tributary streams, and associated embayments such as those occurring in the New Cumberland Pool (e.g., see Section 2.3.1.2). Predominant terrestrial habitats in uplands within reasonable proximity to the river are expected to include forested slopes and ravines, reclaimed mine sites, and agricultural land such as occur in the vicinity of BVPS (see Sections 2.1.2, 2.3.2). Development of the representative plant could result in the loss of substantial amounts of forest habitat, considering the predominance of slope forest and potential use of valley fill for the disposal site. Stream crossings and wetland disturbance, if any, would be subject to provisions, including appropriate mitigation, of a USACE permit (CWA Section 404) and relevant state and local requirements. Considering the large area requirements for the plant and habitats potentially precluded by its development, FENOC concludes that impacts to terrestrial habitats and associated wildlife would be clearly noticeable and could be substantial, depending on location.

Impact to riverine aquatic communities as a result of construction could include some permanent alteration of habitat, particularly for development of a barge terminal for delivery of coal and limestone. Fish and benthic communities would be initially disrupted, but would be expected to reestablish with accompanying localized changes in species composition and distribution in response to changes in bottom substrate availability, water depth, and other factors. Potential for some adverse impact on aquatic communities would persist through the operational period as a result of barge traffic and periodic maintenance dredging. However, such activities are consistent with current activities in the commercially navigable rivers considered in this analysis, and are highly regulated. In particular, riverine construction and maintenance dredging would be conducted in accordance with the provisions of applicable permits from USACE and state authorities, as discussed above in the context of water quality and use impacts.

Operation of the cooling water system for the plant also would be a potential source of impact to aquatic communities. However, this system would be designed and operated in compliance with the CWA, including NPDES limitations for physical and chemical parameters of potential concern and provisions of CWA Sections 316(a) and 316(b), which are respectively established to ensure appropriate protection of aquatic communities from thermal discharges and cooling water intakes. The cooling water intake and discharge flows would be comparable to or less than for BVPS, the impact from which is considered to be SMALL (see Chapter 4). Therefore, associated impacts at a comparable site on commercially navigable river segments assumed for the plant would also be expected to be SMALL.

Under the assumptions of this analysis, environmental impacts on ecological resources related to the location, design, and operational aspects of the representative plant and associated facilities would be subject to regulatory review under OPSB rules or similar programs. FENOC assumed that this review process, including application of appropriate mitigation found to be needed as a result, would ensure that impacts such as those discussed would be noticeable, but not destabilizing. On this basis, FENOC concludes that impacts on ecological resources would be MODERATE.

Socioeconomics
As discussed in Section 7.2.2.2, FENOC assumed that the representative coal-fired alternative would be constructed at a greenfield or brownfield site along the commercially navigable river corridor that exists in the region. The plant would be developed in stages timed to coincide with expiration dates of the BVPS-1 and BVPS-2 operating licenses in 2016 and 2027, respectively. FENOC estimates that a one-unit project would be constructed in approximately 3 years and that a two-unit project would be constructed in approximately 4 years. Average and peak onsite construction workforces are estimated to consist of approximately 1,750 and 2,500 persons, respectively. A permanent workforce of approximately 300 persons is estimated to be required for the completed three-unit plant.

Potential impacts from construction of the coal-fired alternative would be highly location-dependent. As the NRC notes in the GEIS, socioeconomic impacts are expected to be larger at a rural site than at an urban site, because more of the peak construction work force would need to move to the area to work (Ref. 7.0-1, Section 8.3.9). Not considering impacts of terminating BVPS operations, socioeconomic impacts at a remote rural site could be large, while impacts at a site in the vicinity of a more populated metropolitan area (e.g., Pittsburgh) could be small to moderate. FENOC assumed that the OPSB or comparable review process, including application of appropriate mitigation found to be needed as a result, would ensure that these construction impacts would not be destabilizing to local communities.

As noted in Section 7.1.1, communities in Beaver County, particularly those within the tax jurisdiction of the South Side Area School District, would experience losses in both employment and tax revenues due to BVPS closure, assuming the plant is constructed outside the area (see Section 7.1.1). Considering these impacts in combination with construction impacts discussed above, FENOC concludes that overall socioeconomic impacts would be MODERATE.

Human Health
In the GEIS, the NRC cites risk of accidents to workers and public health risks (e.g., cancer, emphysema) from the inhalation of toxics and particulates associated with air emissions as potential risks to human health associated with the coal-fired generation alternative (Ref. 7.0-1, Table 8.2). FENOC assumed that regulatory requirements imposed on facility design, construction, and operations under the authority of the *Occupational Safety and Health Act*, *Clean Air Act*, and related statutes are designed to provide an appropriate level of protection to workers and the public with respect to these risks, and that compliance with those requirements would result in SMALL impacts on human health, regardless of plant location.

Aesthetics
Potential aesthetic impacts of construction and operation of the representative coal-fired plant include visual impairment resulting from the presence of a large industrial facility (including a

building housing the boilers; turbine-generators; emission control equipment; 500-foot-high stacks; fuel, limestone, and waste receiving/handling and storage facilities; stormwater runoff control basins; and cooling towers, up to approximately 500 feet high, with associated condensate plumes). The stacks and condensate plumes from the cooling towers could be visible some distance from the plant. Operation of the waste disposal site could also adversely affect aesthetics with respect to nearby areas. These impacts are highly site-specific. However, considering the current industrial nature of the river corridors considered and presumed consideration of aesthetic impacts and application of appropriate mitigation in the OPSB or comparable review process, FENOC concludes that aesthetic impacts from development and operation of the coal-fired representative plant could range from SMALL to MODERATE, depending on location.

Cultural Resources

FENOC assumed that the representative coal-fired plant and associated waste disposal site and transmission line would be located with consideration of cultural resources under OPSB or comparable rules, and that appropriate measures would be taken to recover or provide other mitigation for loss of any resources discovered during onsite or offsite construction. On this basis, FENOC concludes that the potential adverse impact on cultural resources from this alternative would likely be SMALL.

7.4 REFERENCES

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8.0 COMPARISON OF ENVIRONMENTAL IMPACTS OF LICENSE RENEWAL WITH THE ALTERNATIVES

NRC

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

FENOC presents its evaluations of the environmental impacts associated with BVPS Units 1 and 2 operating license renewal (the proposed action) in Chapter 4 and feasible alternatives in Chapter 7. In this chapter, FENOC provides a comparative summary of these impacts. The environmental impacts comparison addresses Category 2 issues associated with the proposed action and additional issues the NRC identifies in the GEIS (Ref. 8.0-1, Section 8.1) as major considerations in an alternatives analysis. For example, the NRC concluded in the GEIS that air impacts from the proposed action would be small (Category 1), but indicated that there is a potential for major human health concerns associated with air emissions from fossil-fuel generation alternatives (see Section 7.3.1). Inclusion of these additional issues, therefore, establishes a basis for comparison of relevant impacts among alternatives. FENOC provides a comparative summary of its conclusions regarding these issues in Table 8.0-1 and a more detailed comparison in Table 8.0-2.

As indicated in Tables 8.0-1 and 8.0-2, environmental impacts of the proposed action (BVPS license renewal) are expected to be SMALL for all impact categories evaluated. In contrast, FENOC expects that environmental impacts in some impact categories would be MODERATE for the no-action alternative (NRC decision not to renew BVPS operating licenses), considered with or without development of replacement generation facilities. These expected adverse environmental impacts would include the loss of approximately 1,000 permanent jobs and loss of substantial tax revenues from termination of BVPS operations. Notable adverse impacts in the areas of land use, air quality, ecological resources, socioeconomics, and aesthetics might result from replacement of BVPS generating capacity, depending on the alternative selected.

In summary, FENOC's analysis indicates that renewal of the BVPS operating licenses is preferred from an environmental standpoint. With respect to the NRC's decision-making standard at 10 CFR 51.95(c)(4), the analysis supports a conclusion that the option of renewing the BVPS operating licenses should be preserved.

TABLE 8.0-1

IMPACTS COMPARISON SUMMARY

		No-Action Alternative[a]		
Impact	**Proposed Action (License Renewal)**	**Base (Terminate Operations & Decommission)**	**With Gas-Fired Generation**	**With Coal-Fired Generation**
Land Use	SMALL	SMALL	SMALL to MODERATE	MODERATE
Water Use and Quality	SMALL	SMALL	SMALL	SMALL
Air Quality	SMALL	SMALL	MODERATE	MODERATE
Waste Management	SMALL	SMALL	SMALL	MODERATE
Ecological Resources	SMALL	SMALL	SMALL	MODERATE
Socioeconomics	SMALL	SMALL	SMALL	SMALL to MODERATE
Human Health	SMALL	SMALL	SMALL	SMALL
Aesthetics	SMALL	SMALL	SMALL to MODERATE	SMALL to MODERATE
Cultural Resources	SMALL	SMALL	SMALL	SMALL

[a]Impact significance definitions (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.

TABLE 8.0-2

IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)[a]	No-Action Alternative		
	Base (Terminate Operations & Decommission)[a]	With Gas-Fired Generation	With Coal-Fired Generation
Description			
Renew operating licenses for BVPS, extending operation of the units approximately 20 years beyond the expiration of their current operating licenses in 2016 and 2027, respectively (see Chapter 3).	Terminate operations and decommission Unit 1 and Unit 2 following expiration of their current operating licenses in 2016 and 2027, respectively. Adopting, by reference, NRC's description of associated activities provided in the GEIS Chapter 7 and Section 8.4 and in Supplement 1 to NUREG-0586 as representative of corresponding BVPS activities (see Section 7.1.1).	New plant at greenfield site located in northwestern Ohio (see Section 7.2.2.1). Three 530-MW (net) and one 263-MW (net) combined-cycle units. Closed-cycle cooling with mechanical-draft cooling towers. Delivery of natural gas via a new 10-mile-long pipeline. Air emission controls: Nitrogen oxides: water/steam injection; selective catalytic reduction (90% removal). Particulate matter and carbon monoxide emissions limited through proper combustion controls. Exhaust dispersed via 150-foot-tall stacks. Estimated workforce: Construction: 500 average; 900 peak Operation: 80	New plant at a greenfield or, preferably, brownfield site along commercially navigable portions of Allegheny, Monongahela, or Ohio Rivers (see Section 7.2.2.2). Three 600-MW (net) pulverized coal units. Closed-cycle cooling with natural-draft cooling towers. Coal and limestone delivery via barge. Air emission controls: Particulates: fabric filter (99.9% removal) Sulfur oxide: wet limestone scrubber (95% removal) Nitrogen oxide: low nitrogen oxide burners, overfire air, selective catalytic reduction (95% removal). Emissions dispersed via 500-foot-tall stacks. Estimated workforce: Construction: 1,750 average, 2,500 peak Operation: 300

TABLE 8.0-2 (CONTINUED)

IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal) [a]	No-Action Alternative: Base (Terminate Operations & Decommission) [a]	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Coal-Fired Generation
Land Use Impacts			
SMALL – Adopting by reference applicable NRC findings for GEIS Category 1 issues (Issues 52, 53). Tax-driven and population-driven impacts on offsite land use are addressed below under Socioeconomic Impacts. No Category 2 issues.	SMALL – Adopting by reference applicable NRC impact conclusions in the GEIS Section 8.4 and Supplement 1 to NUREG-0586. BVPS decommissioning activities not expected to involve significant land-use disturbance offsite (see Section 7.1.1).	SMALL to MODERATE– Impacts dependent upon location. Approximately 120 acres converted to industrial use at greenfield site. Assumed 10 miles each of 345-kV transmission line on a 150-foot right-of-way and natural-gas supply pipeline on a 50-foot (75-foot for construction) right-of-way, constructed through largely rural agricultural land, resulting in an additional 240 to 270 acres for offsite infrastructure (see Section 7.3.2).	MODERATE– Approximately 260 acres converted to or retained as industrial use for generating and support facilities at a greenfield or brownfield site within a river corridor. Assumed 10 miles of 345-kV transmission line on a 150-foot right-of-way, resulting in an additional 180 acres for offsite infrastructure. Up to 1,400 acres required for offsite disposal of air emissions control waste (see Section 7.3.2).
Water Use and Quality Impacts			
SMALL – Adopting, by reference, applicable NRC findings for GEIS Category 1 issues (Issues 3, 6-11, 89). Under 7Q10 conditions, estimated BVPS consumptive use of the Ohio River would be only 1.1 percent of flow, and USACE maintains New Cumberland Pool at normal pool levels (Section 4.2, Issues 13 and 34).	SMALL – Adopting, by reference, applicable NRC impact conclusions in the GEIS Chapter 7 (as codified in 10 CFR 51, Subpart A, Appendix B, Table B-1) and Section 8.4, and in Supplement 1 to NUREG-0586 (see Section 7.1.1).	SMALL – Construction impacts minimized by use of best management practices and regulatory controls. Cooling water and wastewater discharges subject to regulatory controls (see Section 7.3.1).	SMALL – Construction impacts minimized by use of best management practices and regulatory controls. Operation-phase impacts similar to those of BVPS; cooling water and wastewater discharges subject to regulatory controls (see Section 7.3.2)

TABLE 8.0-2 (CONTINUED)

IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal) [a]	No-Action Alternative: Base (Terminate Operations & Decommission) [a]	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Coal-Fired Generation
Air Quality Impacts			
SMALL – Adopting, by reference, applicable NRC findings for GEIS Category 1 issue (Issue 51, 88). No applicable Category 2 issues.	SMALL – Adopting, by reference, applicable NRC impact conclusions in the GEIS Chapter 7 (as codified in 10 CFR 51, Subpart A, Appendix B, Table B-1) and Section 8.4, and in Supplement 1 to NUREG-0586 (see Section 7.1.1).	MODERATE – Emissions: • 27 tons sulfur dioxide per year • 424 tons nitrogen oxides per year • 643 tons carbon monoxide per year • 81 tons PM_{10} per year (see Section 7.3.1).	MODERATE – Emissions: • 18,000 tons sulfur dioxide per year • 1,400 tons nitrogen oxides per year • 1,400 tons carbon monoxide per year • 330 tons particulate matter per year • 74 tons PM_{10} per year (see Section 7.3.2).
Waste Management Impacts			
SMALL – Adopting, by reference, applicable NRC findings for GEIS Category 1 issues (Issues 77-85, 87). No Category 2 issues.	SMALL – Adopting, by reference, applicable NRC impact conclusions in the GEIS Chapter 7 (as codified in 10 CFR 51, Subpart A, Appendix B, Table B-1) and Section 8.4, and in Supplement 1 to NUREG-0586 (see Section 7.1.1).	SMALL – Relatively low waste generation (see Section 7.3.1).	MODERATE – Waste generated over assumed 40-year plant life disposed of offsite in a 1,400-acre landfill designed to maintain integrity and minimize potential for escape of leachate (see Section 7.3.2).

TABLE 8.0-2 (CONTINUED)

IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal) [a]	No-Action Alternative		
	Base (Terminate Operations & Decommission) [a]	With Gas-Fired Generation	With Coal-Fired Generation
Ecological Resource Impacts			
SMALL – Adopting, by reference, applicable NRC findings for GEIS Category 1 issues (Issues 15-24, 28-30, 41-43, 45-48, and 90). Impacts to threatened and endangered species expected to be small due to one or more of the following: low potential for occurrence in habitats affected by plant and transmission line operation and associated maintenance, protective operation and maintenance practices, and lack of observed impacts as documented by operational monitoring (Section 4.4, Issue 49).	SMALL – Adopting, by reference, applicable NRC impact conclusions in the GEIS Chapter 7 (as codified in 10 CFR 51, Subpart A, Appendix B, Table B-1) and Section 8.4, and in Supplement 1 to NUREG-0586. BVPS decommissioning activities would not be expected to involve significant activities beyond operational areas (see Section 7.1.1).	SMALL - Approximately 120 acres onsite and 240 to 270 acres offsite of largely agricultural land would be converted to industrial use for plant site and offsite infrastructure, respectively; facilities siting would be subject to regulatory controls limiting impacts to ecological resources, including wetlands and threatened or endangered species. Potential for impacts to aquatic resources from construction and operation (e.g., cooling water withdrawal and discharge) reduced by best management practices and regulatory controls (see Section 7.3.1).	MODERATE- Potential loss of up to 260 acres of terrestrial habitat onsite; and an additional potential loss or alteration of 1,580 acres of offsite habitat (e.g., transmission, waste disposal landfill); facilities siting would be subject to regulatory controls limiting impacts to ecological resources, including wetlands and threatened or endangered species. Impact on aquatic habitats and biota from dredging (e.g., for intake and discharge structures and, if applicable, barge terminal), cooling water withdrawal, and discharge would be subject to regulatory controls (see Section 7.3.2).

TABLE 8.0-2 (CONTINUED)

IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal) [a]	No-Action Alternative: Base (Terminate Operations & Decommission) [a]	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Coal-Fired Generation
Socioeconomic Impacts			
SMALL – Adopting, by reference, applicable NRC findings for GEIS Category 1 issues (Issues 64, 67, and 91). Location in area of high population would minimize potential for housing impacts (see Section 4.8, Issue 63). Tax-driven land-use changes would be SMALL considering that property tax assessments for BVPS are expected to be similar to or less than current levels and Beaver County, including Shippingport Borough, has an established development pattern and guides growth with regulatory measures such as zoning and comprehensive planning (see Section 4.11.2, Issue 69). Communities in Beaver and Allegheny Counties have potable water supplies with excess capacity (see Section 4.9, Issue 65). Traffic volume and capacity of major commuting routes would minimize potential for transportation impacts (see Section 4.12, Issue 70).	SMALL– Adopting, by reference, applicable NRC impact conclusions in the GEIS Chapter 7 (as codified in 10 CFR 51, Subpart A, Appendix B, Table B-1) and Section 8.4, and in Supplement 1 to NUREG-0586. Decommissioning activities, as such, would be expected to result in SMALL impact. Potential loss of approximately 1,000 permanent jobs (550 in Beaver County) would result in a SMALL impact (see Section 7.1.1).	SMALL – Reduction in permanent work force could adversely affect surrounding counties, but would be mitigated by plant location within commuting distance of large metropolitan area (e.g., Pittsburgh). Impacts from construction would be mitigated by siting plant within commuting distance of large metropolitan areas. (see Section 7.3.1).	SMALL to MODERATE – Increased demand for housing and public services from nearby communities during construction would likely be small for plant location within commuting distance of large metropolitan area (e.g., Pittsburgh); larger impacts would be possible in more remote rural areas. Regulatory controls and appropriate mitigation would ensure that impacts are not destabilizing (see Section 7.3.2).

TABLE 8.0-2 (CONTINUED)

IMPACTS COMPARISON DETAIL

	No-Action Alternative		
Proposed Action (License Renewal) [a]	Base (Terminate Operations & Decommission) [a]	With Gas-Fired Generation	With Coal-Fired Generation
Human Health Impacts			
SMALL – Adopting, by reference, applicable NRC findings for GEIS Category 1 issues (Issues 56, 58, 61-62, 86). Water temperatures would not support viable populations of thermophilic microbial pathogens, minimizing potential for public health impacts (see Section 4.6, Issue 57). Transmission line-induced currents would conform to National Electric Safety Code® criteria (see Section 4.7, Issue 59).	SMALL – Adopting by reference applicable NRC impact conclusions in the GEIS Chapter 7 (as codified in 10 CFR 51, Subpart A, Appendix B, Table B-1) and Section 8.4, and in Supplement 1 to NUREG-0586 (see Section 7.1.1).	SMALL– Some risk of cancer and emphysema from air emissions and risk of accidents to workers, as the NRC notes in the GEIS. Assumed that regulatory controls would reduce risks to acceptable levels (see Section 7.3.1).	SMALL – Same as for gas-fired alternative (see Section 7.3.2).
Aesthetic Impacts			
SMALL – Adopting, by reference, applicable NRC findings for GEIS Category 1 issues (Issues 73, 74). No Category 2 issues.	SMALL – Adopting, by reference, applicable NRC impact conclusions in the GEIS Section 8.4 and Supplement 1 to NUREG-0586 (see Section 7.1.1).	SMALL to MODERATE – Highly dependent on location. Stacks, cooling tower plumes likely would be visible for several miles. Offsite infrastructure (e.g., transmission) would have adverse impact potential (see Section 7.3.1)	SMALL to MODERATE – Highly dependent on location. Stacks, cooling tower plumes likely would be visible for several miles. Operation of waste disposal site would have adverse impact potential (see Section 7.3.2).

TABLE 8.0-2 (CONTINUED)

IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)[a]	No-Action Alternative: Base (Terminate Operations & Decommission)[a]	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Coal-Fired Generation
Cultural Resource Impacts			
SMALL – No known archaeological or historic resources on site or transmission line corridor except the former SAPS site, which is on the BVPS site and has recognized historic value. However, associated structures are largely dismantled and there are no plans for land-disturbing activities (see Section 4.13, Issue 71).	SMALL – Adopting, by reference, applicable NRC impact conclusions in the GEIS Section 8.4 and Supplement 1 to NUREG-0586. BVPS decommissioning activities would not likely involve significant activities beyond operational areas, and no National Register eligible historic or archaeological resources are known to exist on the BVPS site (see Section 7.1.1).	SMALL –Siting of plant and offsite infrastructure (e.g., transmission line, natural gas pipeline) would be subject to regulatory review, and mitigation measures could be implemented (see Section 7.3.1).	SMALL – Siting of facilities would be subject to regulatory review, and mitigation measures could be implemented (see Section 7.3.2).

[a]See Attachment A, Table A-1, for a list of issues and applicability.

Impact significance definitions (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.

% = percent
Btu = British thermal unit
BVPS = Beaver Valley Power Station
CWA = *Clean Water Act*
EPA = U.S. Environmental Protection Agency
ft = foot/feet
GEIS = *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (Ref. 8.0-1)
kV = kilovolt
MW = megawatt(s)
NRC = U.S. Nuclear Regulatory Commission
PM = particulate matter
PM_{10} = filterable particulates having diameter less than 10 microns
SAPS = Shippingport Atomic Power Station
SHPO = State Historic Preservation Officer
USACE = U. S. Army Corps of Engineers

8.1 REFERENCES

8.0-1 U.S. Nuclear Regulatory Commission. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*. NUREG-1437. Volumes 1 and 2. Office of Nuclear Regulatory Research, Washington, D.C. May 1996. Accession Numbers ML040690705 and ML040690738. Accessed March 2007

9.0 STATUS OF COMPLIANCE

9.1 PROPOSED ACTION

NRC

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

9.1.1 General

Table 9.1-1 lists environmental authorizations that FENOC has obtained for current BVPS site operations. In this context, FENOC uses "authorizations" to include any permits, licenses, approvals, or other entitlements required for plant operations and related activities. FENOC operates BVPS-1 and BVPS-2 using an effective system of monitoring and other management controls to ensure compliance with the provisions of these authorizations and applicable environmental standards and requirements. FENOC would seek timely renewal of these authorizations as needed during the current license period and through the license renewal period and would continue to operate BVPS-1 and BVPS-2 with the objective of ensuring compliance with the provisions of these authorizations and applicable environmental standards and requirements. Because the NRC regulatory focus is prospective, Table 9.1-1 does not include authorizations that FENOC obtained for past activities that did not include continuing obligations.

Before preparing the application for license renewal, FENOC conducted an assessment to identify any new and significant environmental information (Chapter 5). The assessment included interviews with FENOC subject-matter experts, review of BVPS environmental documentation, and communication with state and federal environmental protection agencies. Based on this assessment, FENOC concludes that BVPS is in compliance with applicable environmental standards and requirements.

Table 9.1-2 lists environmental authorizations and consultations related to NRC renewal of the BVPS license to operate. As indicated, FENOC anticipates needing relatively few such authorizations and consultations. Sections 9.1.2 through 9.1.4 discuss some of these items in more detail.

9.1.2 Threatened and Endangered Species Consultation

The *Endangered Species Act*, Section 7 (16 *United States Code* [U.S.C.] 1531 et seq.), requires federal agencies to ensure that an agency action is not likely to jeopardize any species that is listed or proposed for listing as endangered or threatened under that statute. For actions that may adversely affect such species or their habitats, the Act requires consultation with the FWS.

Procedural regulations for the consultation process are set forth at 50 CFR 402, Subpart B. FWS maintains the list of threatened and endangered species at 50 CFR 17.

TABLE 9.1-1

ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT BEAVER VALLEY POWER STATION OPERATIONS

Agency	Authority	Authorization	Number	Issue Date	Expiration	Activity Covered
			Federal Authorizations			
U.S. Nuclear Regulatory Commission	*Atomic Energy Act* [42 U.S.C. 2011 et seq.], 10 CFR 50.10	License to operate	DPR-66 (Unit 1) NPF-73 (Unit 2)	7/2/76 8/14/87	1/29/2016 5/27/2027	Operation of BVPS.
U.S. Department of Transportation	----	Hazardous Material Registration	060503 4450 004L	Issued annually	06/30/2006	Transportation of hazardous materials, Renewed annually
U.S. Environmental Protection Agency	CERCLA [42 U.S.C. s/s 9601 et seq (1980)] EPCRA [42 U.S.C. 11011 et seq (1986)] SARA [42 U.S.C. 9601 et seq (1986)]	CERCLA/EPCRA/ SARA	04-02474 BVPS facility identification number 04-02475 FE Long Term Distribution Center/Warehouse (22)	---- ----	Indefinite Indefinite	Used for SARA Tier II reporting and emergency planning
	RCRA [42 U.S.C. s/s 321 et seq (1976)]	RCRA	PAR000040485	----	Indefinite	Monitor regulated waste activity under the PA Solid Waste Management Act.

TABLE 9.1-1 (CONTINUED)

ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT BEAVER VALLEY POWER STATION OPERATIONS

Agency	Authority	Authorization	Number	Issue Date	Expiration	Activity Covered
Federal Authorizations (continued)						
U.S. Army Corps of Engineers	Section 10 of the *Rivers and Harbors Act* of 1899	U.S. Department of the Army Maintenance Dredging Permit	200100242	4/4/01	12/31/11	Maintenance dredging of the Ohio River along the BVPS auxiliary intake structure, main intake structure, barge slip area, discharge structure, and emergency outfall structure.
State and Local Authorizations						
Pennsylvania Department of Environmental Protection and (for Construction Stormwater Permits) Beaver County Conservation District	*Federal Clean Water Act*, Section 402 (33 U.S.C. Section 1251 et seq.), Pennsylvania Clean Streams Law, Act of June 22, 1937 (P.L. 1987, No. 394), as amended (35 P.S. §691.1 et seq.)	NPDES Individual Wastewater Discharge Permit	PA 0025615	12/27/2001, Amendment 1, 5/13/03)	12/27/2006 *Continued pending approval of renewal application*	Wastewater treatment and effluent discharge to receiving waters (Ohio River and Peggs Run).
		NPDES Construction Stormwater Permits	PAG-2-0004-03-025	12/4/03	12/4/08	Construction of temporary offices at offsite warehouse. Security perimeter expansion.

TABLE 9.1-1 (CONTINUED)

ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT BEAVER VALLEY POWER STATION OPERATIONS

Agency	Authority	Authorization	Number	Issue Date	Expiration	Activity Covered
State and Local Authorizations (continued)						
Pennsylvania Department of Environmental Protection and (for Construction Stormwater Permits) Beaver County Conservation District (continued)			PAG-2-0004-03-027 GP05046203	12/24/03 ----	12/24/08 Upon project completion	General permit for sewage conveyance project to Shippingport Borough Municipal Wastewater treatment facility.
Pennsylvania Department of Environmental Protection	Pennsylvania Code, Title 25, Chapter 245	Storage Tank Registrations and Permits	Unit 1 Facility ID 04-13281 Unit 2 Facility ID 04-13361	Certificate Issued Annually	Annually on October 4, Indefinite	Registration of aboveground and underground storage tanks, as defined in Pennsylvania Code, Title 25, Chapter 245.1, containing regulated substances.
Pennsylvania Department of Environmental Protection[a]	*Pennsylvania Dam Safety and Encroachment Act* of Nov. 26, 1978 (P.L. 1375, No. 325) as amended (32 P.S. §693.1 et seq.)	Water Obstruction and Encroachment Permits	18772 (BVPS-1 entrance road culvert) 19184 (original BVPS-1 construction barge slip) 19522 (Peggs Run relocation)	---- ---- ----	Completed Completed Completed	Allows for operation, maintenance, and normal repair of structures or obstructions built upon waters of the state and the 100-year floodplain.

TABLE 9.1-1 (CONTINUED)

ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT BEAVER VALLEY POWER STATION OPERATIONS

Agency	Authority	Authorization	Number	Issue Date	Expiration	Activity Covered
State and Local Authorizations (continued)						
Pennsylvania Department of Environmental Protection[a] (continued)			0473734 (Peggs Run sheet piling retaining wall)	----	Completed	
			0476713 (cantilever sheet pile wall)	---	Completed	
			0477706 (parking lot fill)	----	Completed	
			0477723 (BVPS-1 and BVPS-2 culvert closing)	----	Completed	
			E-04-85 (BVPS-1 storm sewer)	----	Complete	
			200100242 (0477705 allows maintenance dredging)	----	12/31/2011	
			0477705 (200100242 allows maintenance dredging)	----	Indefinite	
			06786A (transmission line over Ohio River @ Mile 34.5)	----	Indefinite	
			E 04-78 (BVPS-1 emergency outfall/impact basin)	5/11/84	Completed	

TABLE 9.1-1 (CONTINUED)

ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT BEAVER VALLEY POWER STATION OPERATIONS

Agency	Authority	Authorization	Number	Issue Date	Expiration	Activity Covered
State and Local Authorizations (continued)						
Pennsylvania Department of Environmental Protection[a] (continued)			18737 (intake and discharge structures)	8/02/71	Indefinite	
			0475711 (BVPS-2 auxiliary intake structure)	7/07/75	Indefinite	
Pennsylvania Department of Environmental Protection	Clean Air Act, 40 U.S.C. 1857 et seq., *Pennsylvania Air Pollution Control Act* of Jan. 8, 1960, (P.L. 2119)	Air Quality Operating Permit (State Only) (Synthetic Minor)	Beaver Valley Power Station Application for Air Quality Operating Permit #04-086 (State Only) (Synthetic Minor)	Pending	Indefinite (Pending issuance of permit by PADEP)	Establishes emission limits for BVPS emergency diesel generators and the BVPS-2 auxiliary boiler. Pending final approval by PADEP, the application replaces the following separate Air Quality Operating Permits, which are now inactive: 04-302-055 (BVPS-2 auxiliary boilers) 04-399-004 (auxiliary diesel generators) 04-399-005A (Emergency Response Facility diesel generator) 04-399-006 (South Office Shops Building diesel generator)

TABLE 9.1-1 (CONTINUED)

ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT BEAVER VALLEY POWER STATION OPERATIONS

Agency	Authority	Authorization	Number	Issue Date	Expiration	Activity Covered
State and Local Authorizations (continued)						
Pennsylvania Department of Environmental Protection[a]	*Pennsylvania Clean Streams Law*, Act of June 22, 1937 (P.L. 1987, No. 394), as amended (35 P.S. §691.1 et seq.)	Water Management Permit (Part 2 Industrial Wastewater)	048204 [BVPS-2 RBC system (sewage)]	11/10/82	Indefinite	One-time permits allowing for the construction and operation of BVPS site industrial wastewater treatment facilities. Discharges are now regulated under NPDES permit.
			0479403 [BVPS-1 & -2 RBC system (sewage)]	4/01/80		
			0478201 [BVPS-1 oil separator effluent]	2/15/78		
			0473211 [all BVPS-1 and BVPS-2 discharges]	4/11/74		
			0472411 [BVPS-1 package plant (sewage)]	11/6/72		
			0470208 [BVPS-1 radiation and water treating waste]	2/25/71		
			0470203 [BVPS-1 condenser cooling water]	6/26/70		
Pennsylvania Department of Environmental Protection	O25 PA Code 129.14. Open Burning Operations	Open Burning Permit for Firefighting Instruction	NA	Annually in December	Annually on December 31 (12/31/2007)	Periodic open burning of wooden pallets and diesel fuel for purposes of fire brigade training. Operation of the BVPS Fire School.

TABLE 9.1-1 (CONTINUED)

ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT BEAVER VALLEY POWER STATION OPERATIONS

Agency	Authority	Authorization	Number	Issue Date	Expiration	Activity Covered
			State and Local Authorizations (continued)			
Pennsylvania Department of Environmental Protection	Pennsylvania Code, Title 25, Chapter 287.7	Approval for the disposition of intake and cooling tower silt	NA (Letter Concurrence)	12/30/94	Indefinite	Application of dredged and dewatered intake and cooling tower silt at approved areas onsite.
Pennsylvania Department of Environmental Protection	*Pennsylvania Water Resources Planning Act* (Act 220-2002)	Act 220 Water Withdrawal and Use Registration	221113 [Main Intake Structure] 221113 [Alternate Intake] 221113 [Midland Municipal Authority]	3/16/04	Indefinite	Water withdrawal and use/disposition.
Pennsylvania Fish and Boat Commission	Pennsylvania Fish and Boat Code (Act 1980-1975)	Scientific Collector's Permit	036, Type III (R)	Issued Annually	Annually on December 31	Collection of fish and other aquatic life for environmental monitoring programs.
Tennessee Department of Environment and Conservation	Tennessee Code Annotated 68- 202-206	Radioactive Waste License for Delivery	T-PA008-L-99	Issued Annually	Annually on December 31	Shipment of radioactive material to a licensed disposal/processing facility within the State of Tennessee.

TABLE 9.1-1 (CONTINUED)

ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT BEAVER VALLEY POWER STATION OPERATIONS

Agency	Authority	Authorization	Number	Issue Date	Expiration	Activity Covered
			State and Local Authorizations (continued)			
South Carolina Department of Environmental Quality	*South Carolina Radioactive Waste Transportation and Disposal Act* (Act No. 429 of 1980)	Radioactive Waste License for Delivery	0009-37-99-X	Issued Annually	Annually on December 31	Shipment of radioactive material to a licensed disposal/processing facility within the State of South Carolina.

[a]Permit originally issued by Pennsylvania Department of Natural Resources.

BVPS = Beaver Valley Power Station
CERCLA = *Comprehensive Environmental Response, Compensation, and Liability Act*
CFR = *Code of Federal Regulations*
EPCRA = *Emergency Planning and Community Right to Know Act*
ID = Identification Number
NA = Not Applicable
NPDES = National Pollutant Discharge Elimination System
PADEP = Pennsylvania Department of Environmental Protection
P.L. = Public Law
P.S. = Public Statute
RBC = Rotating Biological Contactor
SARA = *Superfund Amendments and Reauthorization Act*
U.S.C. = *United States Code*

TABLE 9.1-2

ENVIRONMENTAL AUTHORIZATIONS FOR BEAVER VALLEY POWER STATION LICENSE RENEWAL

Agency	Authority	Requirement	Remarks
U.S. Nuclear Regulatory Commission	*Atomic Energy Act* (42 U.S.C. 2011 et seq.)	License renewal application	Environmental report submitted in support of license renewal application.
U.S. Fish and Wildlife Service	*Endangered Species Act* Section 7 (16 U.S.C. 1536)	Consultation	Requires federal agency issuing a license to consult with U.S. Fish and Wildlife Service (see Attachment B).
Pennsylvania Department of Environmental Protection	*Clean Water Act* Section 401 (33 U.S.C. 1341)	Certification	Requires federal agency issuing a license to obtain certification from state that the action complies with state water quality standards. State issuance of NPDES permit constitutes 401 certification[a].
Pennsylvania Bureau for Historic Preservation	*National Historic Preservation Act* Section 106 (16 U.S.C. 470f)	Consultation	Requires federal agency issuing a license to consider cultural impacts and consult with State Historic Preservation Officer (see Attachment B).

[a]Ref. 9.1-2

NPDES = National Pollutant Discharge Elimination System
U.S.C. = United States Code

As discussed in Section 4.11, FENOC does not expect continued operation of BVPS-1 and BVPS-2 to affect the population of any federal or state threatened or endangered species, although some listed species have ranges that include the Ohio River and elsewhere in the region of BVPS. Although federal law or NRC regulation does not require it, FENOC invited specific comment from the FWS, the Pennsylvania Game Commission, the Pennsylvania Bureau of Forestry, and the PFBC regarding potential impacts that BVPS-1 and BVPS-2 license renewals might have on species of concern. FENOC made the request to facilitate the NRC's consultation process and to consider potential impacts to species having special status at both the federal and state level. Attachment B is copies of relevant correspondence with these agencies. In addition, FENOC contacted the ODNR and the WVDNR as part of its new and significant information activities (Chapter 5). Responses from these two agencies are acknowledged in Section 4.11 and Table 4.11-1. Based on the assessment presented in Section 4.11, including consideration of correspondence with resource agencies, FENOC concludes that BVPS-1 and BVPS-2 license renewals would not result in significant adverse impact to threatened or endangered species or critical habitats. In December, 2006, FENOC sent letters to the FWS, Pennsylvania Game Commission, Pennsylvania Fish and Boat Commission, and Pennsylvania Department of Conservation and Natural Resources inviting each agency to provide input into the license renewal environmental report review process, and specifically to identify to FENOC any concerns the agency might have regarding license renewal or any information that could potentially be new and significant. No agency raised any issues or questions.

9.1.3 Historic Preservation Consultation

Section 106 of the National Historic Preservation Act (16 U.S.C. 470 et seq.) requires federal agencies to take into account the effect of activities they license on historic properties and to afford the Advisory Council on Historic Preservation an opportunity to comment on the undertaking. Council regulations provide for establishing an agreement with any SHPO to substitute state review for council review (36 CFR 800.7). Although federal law or NRC regulation does not require it, FENOC invited comment from the Pennsylvania SHPO. Attachment B is copies of relevant correspondence. Based on the assessment presented in Section 4.20, including consideration of correspondence with the SHPO, FENOC concludes that BVPS-1 and BVPS-2 operating license renewals would not affect any known historic or archaeological resources. In December, 2006, FENOC sent a letter to the PBHP inviting the PBHP to provide input into the license renewal environmental report review process, and specifically to identify to FENOC any concerns regarding license renewal or any information that could potentially be new and significant. The PBHP raised no issues or questions.

9.1.4 Water Quality (401) Certification

The federal CWA, Section 401, requires an applicant for a federal license or permit that intends to conduct an activity that might result in a discharge into navigable waters to provide the licensing agency certification from the state having jurisdiction that the discharge will comply with applicable CWA standards (33 U.S.C. 1341). FENOC is applying to the NRC for a license (i.e., license renewal) to continue BVPS operations.

The Commonwealth of Pennsylvania has EPA authorization to implement the NPDES program in Pennsylvania for facilities such as BVPS. The NPDES program in the Commonwealth of Pennsylvania is administered by the PADEP. Pursuant to state authority and the EPA authorization, PADEP has issued an NPDES permit for BVPS (Ref. 9.1-1). In the Commonwealth of Pennsylvania, water quality certifications have been integrated with other required approvals or permits (Ref. 9.1-2). In particular, individual water quality certifications are issued only for activities that are not regulated by other water quality approvals or permits, such as an NPDES permit. Therefore, the NPDES permit issued by the PADEP constitutes CWA Section 401 certification by the Commonwealth of Pennsylvania for the continued operations covered by that permit.

9.2 FEASIBLE ALTERNATIVES

NRC
"The discussion of alternatives in the report shall include a discussion of whether the alternatives will comply with such applicable environmental quality standards and requirements." [10 CFR 45(d) as required by 10 CFR 51.53(c)(2)]

It is FENOC's judgment that the representative coal- and gas-fired generation alternatives and purchased-power alternative, presented in Section 7.2.1, could be developed or implemented, as appropriate, to comply with all applicable environmental quality standards and requirements. However, FENOC notes that increasingly stringent air quality protection requirements could make development of a large fossil-fueled power plant infeasible in some locations.

9.3 REFERENCES

Note to reader: This list of references identifies web pages and associated URLs where reference data was obtained. Some of these web pages may likely no longer be available or their URL addresses may have changed. FENOC has maintained hard copies of the information and data obtained from the referenced web pages.

9.1-1 Pennsylvania Department of Environmental Protection, Southwest Regional Office. *Authorization to Discharge Under the National Pollutant Discharge Elimination System.* NPDES Permit No. PA00225615. Pittsburgh, Pennsylvania. December 27, 2001.

9.1-2 Pennsylvania Department of Environmental Protection, Office of Water Management. *400.2 Procedure for 401 Water Quality Certificatio*n. Available at http://164.156.71.80/VWRQ.asp?docid=2087d8407c0e0000000035100000351&context=2&backlink=WXOD.aspx%3ffs%3d7780d840f80b0000800041f0000041f%26ft%3d1. Accessed February 2007.

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ATTACHMENT A DISCUSSION OF NRC LICENSE RENEWAL NATIONAL ENVIRONMENTAL POLICY ACT ISSUES

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

TABLE A-1

BEAVER VALLEY STATION ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

	Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
1.	Impacts of refurbishment on surface water quality	1	4.1	3.4.1/3-4
2.	Impacts of refurbishment on surface water use	1	4.1	3.4.1/3-4
3.	Altered current patterns at intake and discharge structures	1	4.1	4.3.2.2/4-32
4.	Altered salinity gradients	1	NA	Not applicable because BVPS is not in a coastal area
5.	Altered thermal stratification of lakes	1	NA	Not applicable because BVPS does not withdraw cooling water from a lake
6.	Temperature effects on sediment transport capacity	1	4.1	4.3.2.2/4-32
7.	Scouring caused by discharged cooling water	1	4.1	4.3.2.2/4-32
8.	Eutrophication	1	4.1	4.3.2.2/4-32
9.	Discharge of chlorine or other biocides	1	4.1	4.3.2.2/4-32
10.	Discharge of sanitary wastes and minor chemical spills	1	4.1	4.3.2.2/4-32
11.	Discharge of other metals in waste water	1	4.1	4.3.2.2/4-32
12.	Water use conflicts (plants with once-through cooling systems)	1	NA	Not applicable because BVPS is not equipped with once-through heat dissipation systems
13.	Water-use conflicts (plants with cooling ponds or cooling towers using makeup water from a small river with low flow)	2	4.2	4.3.2.1/4-29
14.	Refurbishment impacts to aquatic resources	1	4.1	3.5/3-5
15.	Accumulation of contaminants in sediments or biota	1	4.1	4.3.3/4-33

TABLE A-1 (CONTINUED)

BEAVER VALLEY POWER STATION ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
16. Entrainment of phytoplankton and zooplankton	1	4.1	4.3.3/4-33
17. Cold shock	1	4.1	4.3.3/4-33
18. Thermal plume barrier to migrating fish	1	4.1	4.3.3/4-33
19. Distribution of aquatic organisms	1	4.1	4.3.3/4-33
20. Premature emergence of aquatic insects	1	4.1	4.3.3/4-33
21. Gas supersaturation (gas bubble disease)	1	4.1	4.3.3/4-33
22. Low dissolved oxygen in the discharge	1	4.1	4.3.3/4-33
23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4.1	4.3.3/4-33
24. Stimulation of nuisance organisms (e.g., shipworms)	1	4.1	4.3.3/4-33
25. Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	Identified as NA in 4.3	Not applicable because BVPS is not equipped with cooling ponds or once-through heat dissipation systems.
26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	Identified as NA in 4.4	Not applicable because BVPS is not equipped with cooling ponds or once-through heat dissipation systems.
27. Heat shock for plants with once-through and cooling pond heat dissipation systems	2	Identified as NA in 4.5	Not applicable because BVPS is not equipped with cooling ponds or once-through heat dissipation systems.
28. Entrainment of fish and shellfish in early life stages for plants with cooling tower-based heat dissipation systems	1	4.1	4.3.3/4-33

TABLE A-1 (CONTINUED)

BEAVER VALLEY POWER STATION ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
29. Impingement of fish and shellfish for plants with cooling tower-based heat dissipation systems	1	4.1	4.3.3/4-33
30. Heat shock for plants with cooling tower-based heat dissipation systems	1	4.1	4.3.3/4-33
31. Impacts of refurbishment on groundwater use and quality	1	4.1	3.4.2/3-4
32. Groundwater use conflicts (potable and service water; plants that use < 100 gpm)	1	NA	Not applicable because BVPS does not use groundwater
33. Groundwater use conflicts (potable, service water, and dewatering; plants that use > 100 gpm)	2	Identified as NA in 4.6	Not applicable because BVPS does not use groundwater.
34. Groundwater use conflicts (plants using cooling towers withdrawing makeup water from a small river)	2	4.7	4.8.1.3/4-117
35. Groundwater use conflicts (Ranney wells)	2	Identified as NA in 4.8	Not applicable because BVPS does not use Ranney wells
36. Groundwater quality degradation (Ranney wells)	1	NA	Not applicable because BVPS does not use Ranney wells
37. Groundwater quality degradation (saltwater intrusion)	1	NA	Not applicable because BVPS is not in a coastal area
38. Groundwater quality degradation (cooling ponds in salt marshes)	1	NA	Not applicable because BVPS is not in a coastal area and BVPS is not equipped with cooling ponds
39. Groundwater quality degradation (cooling ponds at inland sites)	2	Identified as NA in 4.9	Not applicable because BVPS is not equipped with cooling ponds.
40. Refurbishment impacts to terrestrial resources	2	4.10	3.6/3-6
41. Cooling tower impacts on crops and ornamental vegetation	1	4.1	4.3.4/4-34

TABLE A-1 (CONTINUED)

BEAVER VALLEY POWER STATION ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
42. Cooling tower impacts on native plants	1	4.1	4.3.5.1/4-42
43. Bird collisions with cooling towers	1	4.1	4.3.5.2/4-45
44. Cooling pond impacts on terrestrial resources	1	NA	Not applicable because BVPS is not equipped with cooling ponds
45. Power line right-of-way management (cutting and herbicide application)	1	4.1	4.5.6.1/4-71
46. Bird collisions with power lines	1	4.1	4.5.6.2/4-74
47. Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4.1	4.5.6.3/4-77
48. Floodplains and wetlands on power line right-of-way	1	4.1	4.5.7/4-81
49. Threatened or endangered species	2	4.11	3.9/3-48, 4.1/4-1
50. Air quality during refurbishment (nonattainment and maintenance areas)	2	4.12	3.3/3-2
51. Air quality effects of transmission lines	1	4.1	4.5.2/4-62
52. Onsite land use	1	4.1	3.2/3-1
53. Power line right-of-way land-use impacts	1	4.1	4.5.3/4-62
54. Radiation exposures to the public during refurbishment	1	4.1	3.8.1/3-29
55. Occupational radiation exposures during refurbishment	1	4.1	3.8.2/3-43
56. Microbiological organisms (occupational health)	1	4.1	4.3.6/4-48

TABLE A-1 (CONTINUED)

BEAVER VALLEY POWER STATION ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
57. Microbiological organisms (public health) (Plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	2	4.13	4.3.6/4-48
58. Noise	1	4.1	4.3.7/4-49
59. Electromagnetic fields, acute effects (electric shock)	2	4.14	4.5.4.1/4-66
60. Electromagnetic fields, chronic effects	NA[c]	4.1	4.5.4.2/4-67
61. Radiation exposures to public (license renewal term)	1	4.1	4.6.2/4-87
62. Occupational radiation exposures (license renewal term)	1	4.1	4.6.3/4-95
63. Housing impacts	2	4.15	3.7.2/3-10, 4.7.1/4-101
64. Public services: public safety, social services, and tourism and recreation	1	4.1	3.7.4/3-14, 4.7.3/4-104
65. Public services: public utilities	2	4.16	3.7.4.5/3-19, 4.7.3.5/4-107
66. Public services: education (refurbishment)	2	4.17	3.7.4.1/3-15
67. Public services: education (license renewal term)	1	4.1	4.7.3.1/4-106
68. Offsite land use (refurbishment)	2	4.18.1	3.7.5/3-20
69. Offsite land use (license renewal term)	2	4.18.2	4.7.4/4-107
70. Public services: transportation	2	4.19	3.7.4.2/3-17, 4.7.3.2/4-106
71. Historic and archaeological resources	2	4.20	3.7.7/3-23, 4.7.7/4-114
72. Aesthetic impacts (refurbishment)	1	4.1	3.7.8/3-27

TABLE A-1 (CONTINUED)

BEAVER VALLEY POWER STATION ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

	Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
73.	Aesthetic impacts (license renewal term)	1	4.1	4.7.6/4-111
74.	Aesthetic impacts of transmission lines (license renewal term)	1	4.1	4.5.8/4-83
75.	Design basis accidents	1	4.1	5.3.2/5-11, 5.5.1/5-114
76.	Severe accidents	2	4.21	5.3.3/5-12, 5.4/5-106, 5.5.2/5-114
77.	Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level radioactive waste)	1	4.1	6.2.4/6-27, 6.6/6-87
78.	Offsite radiological impacts (collective effects)	1	4.1	6.2.4/6-27, 6.6/6-88
79.	Offsite radiological impacts (spent fuel and high-level radioactive waste disposal)	1	4.1	6.2.4/6-28, 6.6/6-88
80.	Nonradiological impacts of the uranium fuel cycle	1	4.1	6.2.2.6/6-20, 6.2.2.7/6-20, 6.2.2.8/6-21, 6.2.2.9/6-21, 6.6/6-90
81.	Low-level radioactive waste storage and disposal	1	4.1	6.4.2/6-36, 6.4.3/6-37, 6.4.4/6-48, 6.6/6-90
82.	Mixed waste storage and disposal	1	4.1	6.4.5/6-63, 6.6/6-91
83.	Onsite spent fuel	1	4.1	6.4.6/6-70, 6.6/6-91
84.	Nonradiological waste	1	4.1	6.5/6-86, 6.6/6-92
85.	Transportation	1	4.1	Addendum 1 (Ref. A.2)
86.	Radiation doses (decommissioning)	1	4.1	7.3.1/7-15, 7.4/7-25
87.	Waste management (decommissioning)	1	4.1	7.3.2/7-19, 7.4/7-25
88.	Air quality (decommissioning)	1	4.1	7.3.3/7-21, 7.4/7-25
89.	Water quality (decommissioning)	1	4.1	7.3.4/7-21, 7.4/7-25

TABLE A-1 (CONTINUED)

BEAVER VALLEY POWER STATION ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
90. Ecological resources (decommissioning)	1	4.1	7.3.5/7-21, 7.4/7-25
91. Socioeconomic impacts (decommissioning)	1	4.1	7.3.7/7-24, 7.4/7-25
92. Environmental justice	NA[c]	2.5.2	Not addressed in GEIS

a. Source: 10 CFR 51, Subpart A, Appendix B, Table B-1 (Issue numbers added by FENOC to facilitate discussion).
b. Source: Ref. A.1.
c. Not applicable. The NRC has not categorized this issue.

BVPS = Beaver Valley Power Station
FENOC = FirstEnergy Nuclear Operating Company
GEIS = *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*
gpm = gallons per minute
NA = Not Applicable
NEPA = National Environmental Policy Act

A.1 REFERENCES

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

A.2 U.S. Nuclear Regulatory Commission. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants. Main Report.* "Section 6.3 – Transportation. Table 9.1 Summary of Findings on NEPA Issues for License Renewal of Nuclear Power Plants." NUREG-1437, Vol. 1, Addendum 1. Office of Nuclear Reactor Regulation. Washington, D.C. August 1999.

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ATTACHMENT B AGENCY CORRESPONDENCE

Item	Description	Page
Federal Threatened or Endangered Species		
B.1	Letter, L. William Pearce (FENOC) to David Densmore (FWS). September 8, 2003.	B-5
B.2	Response Letter, David Densmore (FWS) to L. William Pearce (FENOC). October 2, 2003.	B-25
State Threatened or Endangered Species		
B.3	Letter, L. William Pearce (FENOC) to Frederick G. Carlson (PDCNR). September 8, 2003.	B-29
B.4.	Response Letter, Justin P. Newell (PNDI/PDCNR) to L. William Pearce (FENOC). October 3, 2003.	B-45
B.5.	Letter, L. William Pearce (FENOC) to James R. Leigey (PGC). September 8, 2003.	B-47
B.6	Response Letter, James R. Leigey (PGC) to Mark S. Ackerman (FENOC). October 9, 2003.	B-62
B.7	Letter, L. William Pearce (FENOC) to John A. Arway (PFBC). September 8, 2003.	B-63
B.8	Response Letter, Christopher A. Urban (PFBC) to Mark Ackerman (FENOC). October 29, 2003.	B-92
B.9	Response Letter, L. William Pearce (FENOC) to Christopher A. Urban (PFBC). February 3, 2004.	B-93
Public Health		
B.10	Letter, L. William Pearce (FENOC) to Charles Duritsa (PDEP). September 8, 2003.	B-97
B.11	Response Letter, Charles A. Duritsa (PDEP) to L. William Pearce (FENOC). October 16, 2003.	B-104
Historic and Archaeological Resources		
B.12	Letter, L. William Pearce (FENOC) to Jean Cutler (PBHP). September 8, 2003.	B-105
B.13	Response Letter, Kurt W. Carr (PBHP) to L. William Pearce (FENOC). November 19, 2003.	B-113
B.14	Response Letter, L. William Pearce (FENOC) to Kurt W. Carr (PBHP). February 3, 2004.	B-116
B.15	Response Letter, Kurt W. Carr (PBHP) to L. William Pearce (FENOC). March 12, 2004	B-129

FENOC = FirstEnergy Nuclear Operating Company
FWS = U.S. Fish and Wildlife Service
PDCNR = Pennsylvania Department of Conservation and Natural Resources
PDEP = Pennsylvania Department of Environmental Protection
PFBC = Pennsylvania Fish and Boat Commission
PGC = Pennsylvania Game Commission
PBHP = Pennsylvania Bureau for Historic Preservation
PNDI = Pennsylvania Natural Diversity Inventory

In December 2006, FENOC sent a letter to local, state and federal regulatory agencies and planning commissions asking for input into the license renewal environmental report review process, and specifically to identify to FENOC any concerns of the agency regarding license renewal or any information that could potentially be new and significant. FENOC contacted the following agencies. Correspondence between FENOC and responding agencies is included in Attachment B.

Federal

- U. S. Army Corps of Engineers
- U. S. Environmental Protection Agency, Region 3
- U. S. Fish and Wildlife Service

Pennsylvania

- Bureau of Epidemiology
- Bureau of Radiation Protection
- Department of Conservation and Natural Resources
- Department of Environmental Protection

B.16 Letter, James H. Lash (FENOC) to Kathleen McGinty (PDEP). December 4, 2006. B-130
B.17 Response Letter, Kathleen McGinty (PDEP) to James H. Lash (FENOC). December 15, 2006. B-135
B.18 Letter, James H. Lash (FENOC) to Ronald Schwartz (PDEP). December 4, 2006. B-137
B.19 Response Letter, Ronald Schwartz (PDEP) to Clifford I. Custer (FENOC). December 29, 2006 B-142
B.20 Response Letter, Clifford I. Custer (FENOC) to Ronald Schwartz (PDEP). January 24, 2007 B-147

- Department of Transportation
- Division of Nuclear Safety
- Emergency Management Agency
- Fish and Boat Commission

B.21 Letter, James H. Lash (FENOC) to Douglas J. Austen (PF&BC). December 4, 2006. B-148
B.22 Response Letter, Christopher A. Urban (PF&BC) to Julie Firestone (FENOC). March 2, 2007. B-153

- Game Commission

B.23 Letter, James H. Lash (FENOC) to James R. Leigey (PGC). December 4, 2006. B-154
B.24 Response Letter, James R. Leigey (PGC) to Clifford I. Custer (FENOC). January 8, 2007. B-159

- Beaver County Emergency Management Agency
- Beaver County Chamber of Commerce
- Beaver County Conservation District
- Beaver County Corporation for Economic Development
- Pittsburgh City Planning

West Virginia

- Department of Environmental Protection
- Division of Culture and History

B.25 Letter, James H. Lash (FENOC) to Caroline Kender (WVDCH). December 4, 2006. B-160
B.26 Response Letter, Susan M. Pierce (WVDCH) to Clifford I. Custer (FENOC). January 9, 200[6]. B-165
B.27 Response Letter, Clifford I. Custer (FENOC) to Susan M. Pierce (WVDCH). February 20, 2007. B-167
B.28 Response Letter, Susan M. Pierce (WVDCH) to Clifford I. Custer (FENOC). March 14, 200[6]. B-169

- Division of Natural Resources
- Division of Water Resources
- Office of Homeland Security and Emergency Services
- Radiological Health Program
- State Historic Preservation Office

- Brook County
- Hancock County Office of Emergency Management

Ohio

- Bureau of Radiation Protection
- Department of Health, Radiological Emergency Response
- Department of Natural Resources

B.29 Letter, James H. Lash (FENOC) to Samuel W. Speek (ODNR). December 4, 2006. B-170
B.30 Response Letter, Mindy Bankey (ODNR) Clifford I. Custer (FENOC). December 29, 2006. B-175

- Emergency Management Agency
- Historic Preservation Office

- Brook-Hancock-Jefferson Metropolitan Planning Commission
- Lazarus Government Center

- Ohio Environmental Protection Agency
- River Valley Sanitation Commission
- Columbiana County Emergency Management Agency
- East Liverpool Area Chamber of Commerce
- Salem Area Chamber of Commerce

Kentucky

- Ohio River Basin Commission

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

L. William Pearce
Site Vice President

724-682-5234
Fax: 724-643-8069

September 8, 2003
L-03-087

Mr. David Densmore
Supervisor
U.S. Fish and Wildlife Service
Pennsylvania Field Office
315 South Allen Street, Suite 322
State College, PA 16801-4850

Subject: Beaver Valley Power Station License Renewal Project
Request for Information and Concurrence - Threatened & Endangered Species

Reference: Letter CNS-02-050, Julea B. Hovey, Constellation Nuclear Services, to Dr. Mamie Parker, U.S. Fish and Wildlife Service, June 28, 2002

Dear Mr. Densmore:

FirstEnergy Nuclear Operating Company (FENOC) is preparing an environmental report as part of our operating license renewal application (LRA) to the U.S. Nuclear Regulatory Commission (NRC) for the Beaver Valley Power Station (BVPS) Units 1 and 2. BVPS Units 1 and 2 have been in operation since 1976 and 1987, respectively. Successful renewal would provide the opportunity to operate the units for up to 20 years beyond the expiration of their current licenses in 2016 and 2027, respectively.

In correspondence to the U.S. Fish and Wildlife Service (FWS) referenced above, FENOC's LRA consultant indicated that the LRA environmental review would include an assessment of potential impacts of BVPS license renewal on threatened, endangered, and candidate species. Since that time, FENOC has completed a preliminary draft of an assessment of potential impacts on species within FWS jurisdiction, which will be finalized and included in the LRA environmental report. Accordingly, FENOC is now requesting FWS assistance in finalizing our assessment to provide additional assurance that it is accurate and complete. By contacting you at this time, FENOC believes that the effectiveness of forthcoming NRC interactions with your office, described in the following paragraph, will be enhanced.

The NRC, at 10 CFR 51.53(c)(3)(ii)(E), requires that license renewal applicants ". . . assess the impact of the proposed action {license renewal} on threatened and endangered species in accordance with the Endangered Species Act." The NRC staff routinely interacts with other affected agencies in conducting their environmental review, which leads to preparation of a supplemental environmental impact statement (SEIS) for this licensing action. It is expected that the FWS will be contacted regarding potential impact on species within its jurisdiction as part of this activity. The following paragraphs describe relevant aspects of the BVPS environmental setting considered in the LRA and a synopsis of FENOC's assessment of potential impacts of BVPS license renewal on species of interest.

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Page 2

The BVPS site consists of approximately 450 acres on the south side of the Ohio River (New Cumberland Pool) at Shippingport, Beaver County, Pennsylvania (see Attachment 1, Figure 1). The intensively developed or maintained portion of the site, approximately 220 acres, is located on a gravel terrace adjacent to the river; the remainder of the site consists mostly of forested slopes. BVPS employs a closed-cycle cooling system (cooling towers), and withdraws cooling water, primarily makeup water for this system, from the Ohio River at the Intake Structure. Cooling water, primarily cooling tower blowdown, is discharged to the Ohio River at the Discharge Structure and Emergency Overflow Structure and Impact Basin, along with small volumes of treated wastewater, in accordance with provisions of NPDES Permit PA0025615.

Short segments of three transmission lines on and adjacent to the BVPS site and one transmission line extending 15.8 miles southeast from BVPS (Duquesne Light Company's Beaver Valley-Crescent Line 318) are also being addressed in the BVPS LRA environmental report (see Attachment 1, Figures 2 and 3). The latter transmission line corridor traverses primarily through forest and farmland. Based on review of National Wetland Inventory maps, wetlands on or adjacent to this corridor are limited to a small (2-acre) palustrine forested area at the span of Service Creek and possibly one or more very small strips of riparian emergent vegetation at the span of Raccoon Creek (Attachment 1, Figure 3). The transmission line segments being considered in the LRA environmental report have been in service since the mid-1980s.

Based on our preliminary draft assessment, summarized in Attachment 2, FENOC believes that extended operation and maintenance of BVPS and the transmission corridors considered in the LRA would have no significant impact on federally threatened, endangered, or candidate species. FENOC has not identified any land disturbing activities that would be undertaken for license renewal, and both FENOC and Duquesne Light would continue to be subject to applicable regulatory controls for the period of extended operation. Neither FENOC nor Duquesne Light is aware of any adverse impact to any federally threatened, endangered, or candidate species from past or current operation of BVPS or these transmission lines.

FENOC respectfully requests that the FWS (1) formally notify us of any concerns or additional relevant information regarding threatened, endangered, and candidate species pertinent to our preliminary draft assessment and (2), as appropriate, concur with the assessment. FENOC will evaluate any information you provide for inclusion in the assessment, and will include your response to this request in the final LRA environmental report submitted to the NRC. FENOC would appreciate receiving your response within 60 days of receipt to provide ample time to evaluate and incorporate your response into our LRA environmental report for submittal to the NRC.

Thank you for your assistance as we complete this important environmental assessment. Please address any comments or questions you may have to Mr. Mark Ackerman, License Renewal Project Manager, by telephone at (724) 682-7994, e-mail ackermanm@firstenergycorp.com, or at the letterhead address above.

Sincerely,

L. W. Pearce

L. William Pearce
Site Vice President

Attachments: Project Maps (Attachment 1)
Preliminary Assessment (Attachment 2)

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Page 3

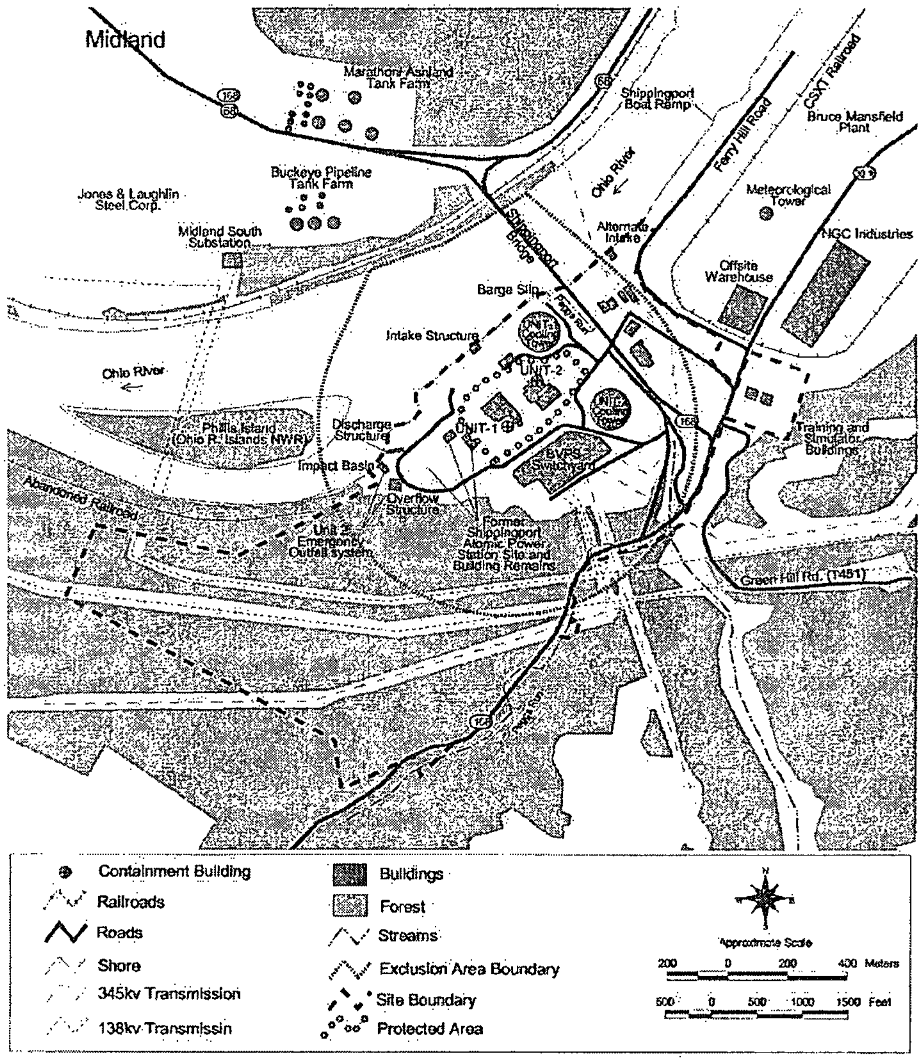
bc: G. DeCamp (CNS)
T. Grenci (CNS)
M. S. Ackerman (3 copies)
Central File

ATTACHMENT 1

PROJECT MAPS

FIGURE 1

BEAVER VALLEY POWER STATION SITE MAP

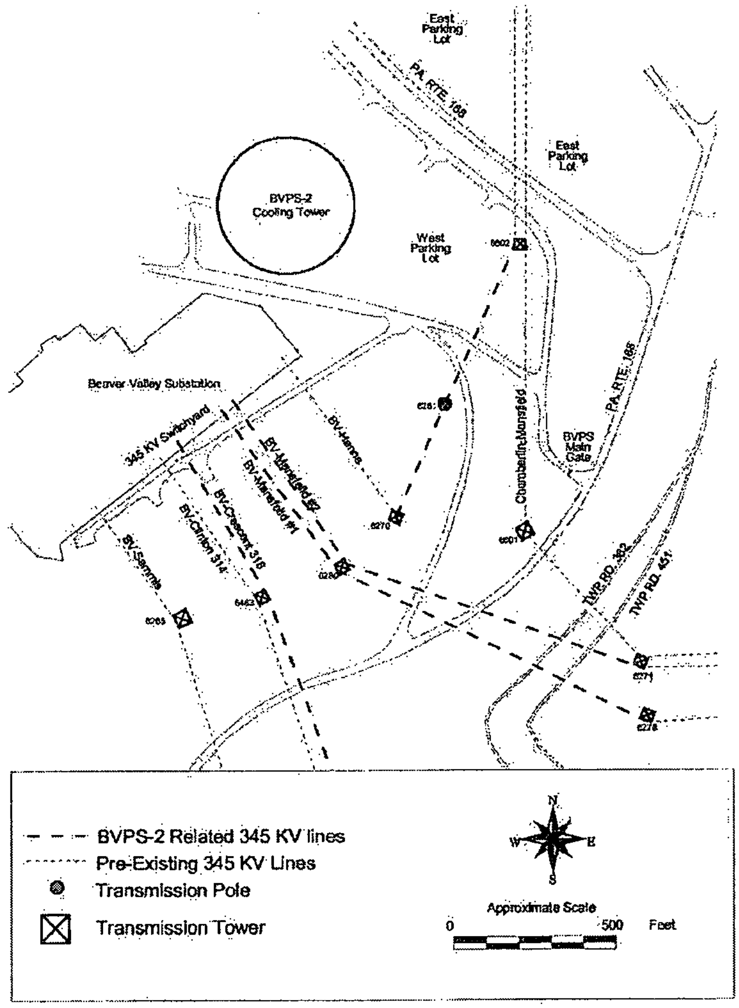


BVPS LRA Environmental Review
Project Maps

Att. 1-1

FIGURE 2

345 kV RECONFIGURATIONS FOR BEAVER VALLEY POWER STATION UNIT 2

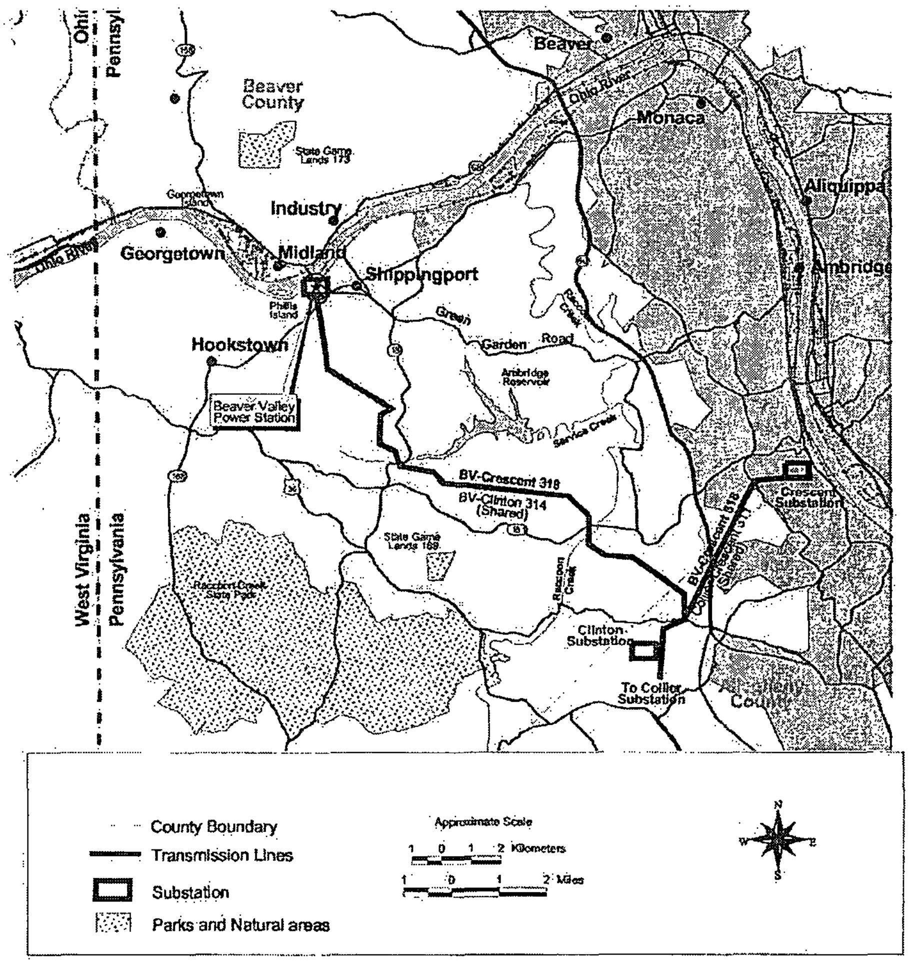


BVPS LRA Environmental Review
Project Maps

Att. 1-2

FIGURE 3

BEAVER VALLEY-CRESCENT LINE 318 CORRIDOR



BVPS LRA Environmental Review
Project Maps

Att. 1-3

ATTACHMENT 2

PRELIMINARY ASSESSMENT

FEDERAL THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL

TABLE 1

FEDERAL THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL[a]

Common Name Scientific Name	U.S. Status	PA Status	Habitat/Occurrence
			Aquatic Invertebrates
Northern riffleshell *Epioblasma torulosa rangiana*	E	E	Large and small streams, preferring runs with bottoms of firmly packed sand and fine to coarse gravel; recent occurrence in PA limited to upper Allegheny River watershed (Ref. 1; Ref. 2). No recent documented occurrences in Ohio River downstream as far as Meldahl Pool (Ref. 3). No PNDI record of observation in lower Allegheny River/Upper Ohio River in PA since 1919 or earlier (Ref. 4, Appendix J). Not reported by PNDI or PFBC as occurring in the Ohio River or other water bodies in the vicinity of the BVPS site or Beaver Valley-Crescent Line 318 (Ref. 5, Ref. 6, Ref. 7, Ref. 8).
Clubshell *Pleurobema clava*	E	E	Small rivers and streams in clean-sweep sand and gravel; has been found buried 2-4 inches in clean, loose sand. Recent occurrence in Ohio River drainage in PA limited to upper Allegheny River watershed. (Ref. 9). No recent documented occurrences in Ohio River downstream as far as Meldahl Pool (Ref. 3). No PNDI record of observation in lower Allegheny River/Upper Ohio River in PA since 1919 or earlier (Ref. 4, Appendix J). Not reported by PNDI or PFBC as occurring in the Ohio River or other water bodies in the vicinity of the BVPS site or Beaver Valley-Crescent Line 318 (Ref. 5, Ref. 6, Ref. 7, Ref. 8).
			Plants
Small whorled pogonia *Isotria medeoloides*	T	E	Nearly all populations occur in second growth or relatively mature forests. PA populations most abundant on dry east- or southeast-facing hillsides in mixed oak forest on rocky, somewhat acidic soils. Only 2 occurrences in PA verified since 1980. Known historical occurrence in southwestern PA only in Greene Co. (Ref. 10). Specifically reported as not observed during ecological surveys of the BVPS site in 1974-1975 (Ref. 11). Not identified by PNDI as potentially occurring in the vicinity of the BVPS site or Beaver Valley-Crescent Line 318 transmission line corridor (Ref. 5, Ref. 7; Ref. 12).

Common Name Scientific Name	U.S. Status	PA Status	Habitat/Occurrence
Reptiles			
Eastern massasauga *Sistrurus catenatus*	C	E	Relatively open old field and wet meadow habitat with low-lying areas of saturated soil and higher, drier ground nearby, which is found in PA only in relic prairie terrain in western counties. No historical occurrences in Beaver County; historical occurrence in northeastern Allegheny Co., but not since 1980 (Ref. 13). However, both Counties are south of its range as indicated by Conant (Ref. 14). This species was not collected or observed in ecological surveys of the BVPS site in 1974-75 (Ref. 11, Table 2.2-16) or site reconnaissance conducted in 2002 (Ref. 15), and little or no wetland habitat suitable for this species exists in the BVPS site vicinity or along the Beaver Valley-Crescent Line 318 corridor. This species was not identified by PNDI or PFBC as potentially occurring in the vicinity of the BVPS site or Beaver Valley-Crescent Line 318 transmission line corridor (Ref. 5; Ref. 6, Ref. 7, Ref. 8).
Birds			
Bald Eagle *Haliaeetus leucocephalus*	T	E	Thrives around bodies of water where adequate food exists and human intrusions and disturbance is limited. PA populations are recovering from effects of the pesticide DDT, the primary reason for the population decline. From 1997 to 1999, the PA nesting population more than doubled to 43 pairs; however, no nesting has been reported in Beaver or Allegheny Counties as of 1999 (Ref. 16). Individuals are occasionally observed along the Ohio River at BVPS. Not identified by PNDI as a potential conflict for the BVPS site vicinity or Beaver Valley-Crescent Line 318 transmission line corridor (Ref. 5; Ref. 7). PA Game Commission (Ref. 17) review indicates that, except for occasional transient individuals, the BVPS site is not located in an area that is habitat for an endangered or threatened species of bird recognized by the PA Game Commission.
Mammals			
Indiana bat *Myotis sodalis*	E	E	Hibernates in winter in communal caves, usually with standing or flowing water, of which nine are known in PA (none in Beaver and Allegheny Counties). Known summer habitat includes maternal colonies behind flaking bark on dead or dying trees along stream or river corridors, and upland forests. Primary threat is disturbance to hibernating populations and hibernation sites (Ref. 18). Not identified by PNDI as a potential conflict for the BVPS site vicinity or Beaver Valley-Crescent Line 318 transmission line corridor (Ref. 5; Ref. 7). PA Game

Common Name Scientific Name	U.S. Status	PA Status	Habitat/Occurrence
			Commission (Ref. 17) review indicates that, except for occasional transient individuals, the BVPS site is not located in an area that is habitat for an endangered or threatened species of mammal recognized by the PA Game Commission.

a. Tabulated species include federally designated threatened, endangered, and candidate species reported by the U.S. Fish and Wildlife Service (FWS) for Pennsylvania (Ref. 19, Ref. 20) with known historical ranges that include the upper Ohio River or southwestern Pennsylvania, except those considered to be extirpated in PA, e.g., by the Pennsylvania Biological Survey (Ref. 21).

FWS = U.S. Fish and Wildlife Service
BVPS = Beaver Valley Power Station
PA = Pennsylvania
PFBC = Pennsylvania Fish and Boat Commission
PNDI = Pennsylvania Natural Diversity Inventory

TABLE 2

SUMMARY IMPACT ASSESSMENT FOR FEDERAL THREATENED, ENDANGERED, AND CANDIDATE SPECIES OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL[a]

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
Invertebrates			
Northern riffleshell *Epioblasma torulosa rangiana* FE, PE Clubshell *Pleurobema clava* FE, PE The following species listed by FWS for PA are considered to be extirpated by the PA Biological Survey: Pink mucket *Lampsilis abrupta* FE Rough pigtoe *Pleurobema plenum* FE Orangefoot pimpleback *Plethobasus cooperianus* FE	None to Low. Last documented occurrence in the upper Ohio River or lower Allegheny River in early 1900s. However, recent surveys have documented the presence in the New Cumberland Pool, including the Phillis Island backchannel, of other unionid mussel species not recorded there since the early 1900s, and indicate that some federally listed mussels may recolonize upper Ohio River pools in the future (Ref. 3).	(Applicable to all) Maintenance dredging (e.g., barge slip). Cooling water and wastewater discharges. Unplanned petroleum or hazardous materials spills/releases.	(Applicable to all) • Maintenance dredging is regulated by USACE and PADEP permits. • Cooling water and wastewater discharges are regulated by NPDES permit, which includes discharge limits and monitoring requirements. • Controls are established for prevention, preparedness, and response to unplanned spills and releases (e.g., *BVPS Preparedness, Prevention, and Contingency Plan*) • Closed-cycle cooling and tendency of plume to remain at surface, and low probability of simultaneous shutdown of both BVPS units reduces potential for adverse thermal impacts. • Unionid mussel population increase or recolonization at Phillis Island, downstream from BVPS outfall, apparently has occurred since BVPS initiated operation. • Benthic macroinvertebrate monitoring at BVPS, conducted annually from 1973 through present, indicates that BVPS is not adversely affecting the benthic macroinvertebrate community. The NRC concurred and deleted the requirement for benthic macroinvertebrate monitoring in 1980 with Amendment 25 to the BVPS-1 Technical Specifications. • FENOC has not identified any significant land disturbing activities that would be undertaken for license renewal either on or in the vicinity of the BVPS site or along the Beaver Valley-Crescent Line 318 corridor. • Results of PNDI searches (Ref. 5, Ref. 6, Ref. 7, Ref. 8)

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
			conducted at FENOC's request have not identified these or other federally listed or candidate invertebrate species as potential conflicts with BVPS or transmission line operation. Impact Conclusion: SMALL
		Plants	
Small whorled pogonia *Isotria medeoloides* FT, PE	None to Low on BVPS site. Low on or near Beaver Valley – Crescent Line 318 corridor. Specifically reported as not observed during ecological surveys of the BVPS site in 1974-1975 (Ref. 11). Not reported in PNDI searches for either BVPS site (Ref. 5) or transmission corridor (Ref. 7, Ref. 12) None currently known from southwestern Pennsylvania.	Vegetation maintenance on BVPS site and transmission line corridor.	• FENOC and Duquesne Light maintenance practices on transmission corridors are limited to selective pruning or removal of trees that could interfere with the line and selective pruning or herbicide use to control incompatible vegetation. EPA-approved herbicides are selectively applied in accordance with manufacturer's label requirements by state-licensed applicators. • Similar vegetation practices to those employed on transmission line corridors are used on BVPS site to maintain cleared areas as needed for site security. • FENOC has not identified any land disturbing activities that would be undertaken for license renewal. • Both FENOC and Duquesne Light would continue to be subject to applicable regulatory controls for the period of extended operation. • Neither FENOC nor Duquesne Light is aware of any adverse impact to any threatened, endangered, or candidate plant species from past or current operation of BVPS or transmission lines being considered in the license renewal environmental review. • Forested areas within the Beaver Valley Crescent Line 318 corridor exist only at the bottom of some spanned ravines and valleys and along the corridor edge in some segments, reducing potential for disturbance of potentially compatible habitat. • Results of PNDI searches (Ref. 5, Ref. 7, Ref. 12)

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
			conducted at FENOC's request have not identified these or other federally listed or candidate plant species as potential conflicts with BVPS or transmission line operation. Impact Conclusion: SMALL
Reptiles			
Eastern massasauga *Sistrurus catenatus* FC, PE	None to Low. No recent confirmed occurrence in Beaver or Allegheny Counties. Little or no suitable wetland habitat on or near BVPS site or Beaver Valley-Crescent Line 318 transmission corridor. Not collected or observed in 1974-75 ecological surveys of BVPS site (Ref. 11, Table 2.2-16) or 2002 site reconnaissance (Ref. 15)	No significant initiators.	• Results of PNDI searches (Ref. 5, Ref. 6, Ref. 7, Ref. 8) conducted at FENOC's request have not identified this or other federally listed or candidate species as potential conflicts with BVPS or transmission line operation. Impact Conclusion: SMALL

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
		Birds	
Bald Eagle *Haliaeetus leucocephalus* FT, PE	High for transient or foraging individuals. Occasional individuals are observed along the Ohio River at the BVPS site. None to Low for future nesting on or near BVPS site considering industrial development and human activity. Low to Moderate for future nesting along Beaver Valley-Crescent Line 318 transmission corridor considering undeveloped areas near Ambridge Reservoir.	Collision with cooling towers or transmission lines.	• Surveys of bird collisions at the BVPS-1 cooling tower in spring and fall from 1974 through 1978 found a total of only 27 dead birds (26 passerines and one rail) (Ref. 11, Page 5.1-21). • FirstEnergy and Duquesne Light are not aware of any reports of impact or electrocutions of this species associated with Beaver Valley-Crescent Line 318 or transmission line relocations addressed in the BVPS license renewal environmental review. • Results of PNDI searches (Ref. 5, Ref. 7) conducted at FENOC's request have not identified this or other federally listed or candidate bird species as potential conflicts with BVPS or transmission line operation. • PA Game Commission (Ref. 17) indicates that, except for occasional transient individuals, BVPS is not located in an area that is habitat for an endangered or threatened bird under their jurisdiction, nor are any long-term adverse impacts to associated critical or unique habitats anticipated from BVPS operation. Impact Conclusion: SMALL

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
		Mammals	
Indiana bat *Myotis sodalis* FE, PE	None for hibernating colonies. Low for maternal colonies on BVPS site. Not collected or observed in 1974-75 ecological surveys of BVPS site (Ref. 11, Table 2.2-16). Low for maternal colonies in trees bordering Beaver Valley-Crescent Line 318 transmission corridor.	Removal of maternal colony trees bordering transmission corridor.	• Corridor maintenance practices limit removal of mature trees to those that could interfere with transmission lines. • Streams along corridor are frequently in relatively deep narrow valleys that are spanned, reducing the necessity to clear riparian trees. • Results of PNDI searches (Ref. 5, Ref. 7) conducted at FENOC's request have not identified this or other federally listed or candidate mammal species as potential conflicts with BVPS or transmission line operation. • PA Game Commission (Ref. 17) indicates that, except for occasional transient individuals, BVPS is not located in an area that is habitat for an endangered or threatened mammal under their jurisdiction, nor are any long-term adverse impacts to critical or unique habitats anticipated from BVPS operation. Impact Conclusion: SMALL

TABLE 2

SUMMARY IMPACT ASSESSMENT FOR
THREATENED, ENDANGERED, AND CANDIDATE SPECIES
SUBJECT TO PENNSYLVANIA FISH AND BOAT COMMISSION JURISDICTION
OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL[a]

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
Invertebrates			
Northern riffleshell *Epioblasma torulosa rangiana* FE, PE Clubshell *Pleurobema clava* FE, PE	(Applicable to all) None to Low. Last *documented* occurrence in the upper Ohio River or lower Allegheny River in early 1900s. However, recent surveys have documented the presence in the New Cumberland Pool, including the Phillis Island backchannel, of other unionid mussel species not recorded there since the early 1900s, and indicate that some mussels listed by PA or FWS may recolonize upper Ohio River pools in the future (Ref. 3).	(Applicable to all) *Maintenance* dredging (e.g., barge slip) Cooling water and wastewater discharges. Unplanned petroleum or hazardous materials spills/releases.	(Applicable to all) • Maintenance dredging is regulated by USACE and PADEP *permits*. • Cooling water and wastewater discharges are regulated by NPDES permit, which includes discharge limits and monitoring requirements. • Controls are established for prevention, preparedness, and response to unplanned spills and releases (e.g., *BVPS Preparedness, Prevention, and Contingency Plan*) • Closed-cycle cooling, tendency of plume to remain at surface, and low probability of simultaneous shutdown of both BVPS units reduces potential for adverse thermal impacts. • Unionid mussel population increase or recolonization at Phillis Island, downstream from BVPS outfall, apparently has occurred since BVPS initiated operation. • Benthic macroinvertebrate monitoring at BVPS, conducted annually from 1973 through present, indicates that BVPS is not adversely affecting the benthic macroinvertebrate community. The NRC concurred and deleted the requirement for benthic macroinvertebrate monitoring in 1980 with Amendment 25 to the BVPS-1 Technical Specifications. • FENOC has not identified any significant land disturbing activities that would be undertaken for license renewal either

REFERENCES

1. Pennsylvania Department of Conservation and Natural Resources. *Epioblasma torulosa rangiana.* http://www.dcnr.state.pa.us/wrcf/rif.htm. Accessed October 12, 2002.

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6. Pennsylvania Fish and Boat Commission. Letter SIR #9555 from John A. Arway, Pennsylvania Fish and Boat Commission, to Michael D. Banko III, FENOC. "Species Impact Review (SIR) – Rare, Candidate, Threatened and Endangered Species, PNDI Potential Conflict Number N100081, FirstEnergy Nuclear Operating Company, Beaver Valley Power Station Operating License, Shippingport Township, Beaver County, Pennsylvania". September 16, 2002.

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United States Department of the Interior

FISH AND WILDLIFE SERVICE
Pennsylvania Field Office
315 South Allen Street, Suite 322
State College, Pennsylvania 16801-4850

October 2, 2003

L. William Pearce
FirstEnergy Nuclear Operating Company
Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

Dear Mr. Pearce:

This responds to your letter of September 8, 2003, requesting information about federally listed and proposed endangered and threatened species within the vicinity of the Beaver Valley Power Station located in Beaver County, Pennsylvania. The following comments are provided pursuant to the Endangered Species Act of 1973 (87 Stat. 884, as amended; 16 U.S.C. 1531 *et seq.*) to ensure the protection of endangered and threatened species.

Except for occasional transient species, no federally listed or proposed threatened or endangered species under our jurisdiction are known to occur within the project impact area. Therefore, no biological assessment nor further consultation under the Endangered Species Act are required with the Fish and Wildlife Service. This determination is valid for two years from the date of this letter. If the proposed project has not been fully implemented prior to this, an additional review by this office will be necessary. Also, should project plans change, or if additional information on listed or proposed species becomes available, this determination may be reconsidered. A compilation of certain federal status species in Pennsylvania is enclosed for your information.

This response relates only to endangered or threatened species under our jurisdiction based on an office review of the proposed project's location. No field inspection of the project area has been conducted by this office. Consequently, this letter is not to be construed as addressing potential Service concerns under the Fish and Wildlife Coordination Act or other authorities.

Requests for information regarding State-listed endangered or threatened species should be directed to the Pennsylvania Game Commission (birds and mammals), the Pennsylvania Fish and Boat Commission (fish, reptiles, amphibians and aquatic invertebrates), and the Pennsylvania Department of Conservation and Natural Resources (plants).

Please contact Michael Schmaus of my staff at 814-234-4090 if you have any questions or require further assistance.

Sincerely,

David Densmore
Supervisor

Enclosure

2

FEDERALLY LISTED, PROPOSED AND CANDIDATE SPECIES
(in Pennsylvania)

Common Name	Scientific Name	Status[1]	Distribution (by County and/or Watershed)
FISHES			
Shortnose sturgeon[2]	*Acipenser brevirostrum*	E	Delaware River & other Atlantic coastal waters
REPTILES			
Bog turtle	*Clemmys muhlenbergii*	T	Current - Adams, Berks, Bucks, Chester, Cumberland, Delaware, Franklin, Lancaster, Lebanon, Lehigh, Monroe, Montgomery, Northampton, Schuylkill, York; Historic - Crawford, Mercer, Philadelphia Co.
Eastern massasauga rattlesnake	*Sistrurus catenatus catenatus*	C	Current - Butler, Crawford, Mercer and Venango Co. Historic - Allegheny and Lawrence Co.
BIRDS			
Bald eagle	*Haliaeetus leucocephalus*	T	Suitable habitats across the state. Recent nesting in Butler, Cameron, Centre, Chester, Crawford, Dauphin, Erie, Forest, Huntingdon, Lancaster, Lebanon, Mercer, Northumberland, Pike, Tioga, Venango, Warren, Wayne and York Co. Wintering concentrations occur near ice-free sections of rivers, lakes and reservoirs, including the Delaware River.
Piping plover	*Charadrius melodus*	E	Migratory. No nesting in Pennsylvania since 1950s. Designated critical habitat on Presque Isle, Erie Co.
MAMMALS			
Indiana bat	*Myotis sodalis*	E	Winter hibernacula: Armstrong, Blair, Lawrence, Luzerne, Mifflin and Somerset Co.
MOLLUSKS			
Dwarf wedgemussel	*Alasmidonta heterodon*	E	Current - Delaware River (Wayne Co.). Historic - Delaware River watershed (Bucks, Carbon, Chester and Philadelphia Co.); Susquehanna River watershed (Lancaster Co.)
Clubshell mussel	*Pleurobema clava*	E	French Creek and Allegheny River watersheds (Clarion, Crawford, Erie, Forest, Mercer, Venango and Warren Co.); Shenango River (Ohio River watershed; Mercer and Crawford Co.)
Northern riffleshell	*Epioblasma torulosa rangiana*	E	French Creek and Allegheny River watersheds (Clarion, Crawford, Erie, Forest, Mercer, Venango and Warren Co.)
PLANTS			
Northeastern bulrush	*Scirpus ancistrochaetus*	E	Current - Adams, Bedford, Blair, Carbon, Centre, Clinton, Cumberland, Dauphin, Franklin, Huntingdon, Lackawanna, Lehigh, Lycoming, Mifflin, Monroe, Perry, Snyder and Union Co. Historic - Northampton Co.
Small-whorled pogonia	*Isotria medeoloides*	T	Current - Centre, Chester and Venango Co. Historic - Berks, Greene, Monroe, Montgomery and Philadelphia Co.

[1] *E = Endangered; T = Threatened, PE = Proposed Endangered; PT = Proposed Threatened, C = Candidate* *Revised 2/27/03*
[2] *Shortnose sturgeon is under the jurisdiction of the National Marine Fisheries Service*

U.S. FISH AND WILDLIFE SERVICE
315 SOUTH ALLEN ST., SUITE 322, STATE COLLEGE, PA 16801

FEDERALLY LISTED AND PROPOSED SPECIES THAT NO LONGER OCCUR IN PENNSYLVANIA

COMMON NAME	SCIENTIFIC NAME	STATUS**	FORMER DISTRIBUTION
MAMMALS			
Canada lynx	*Lynx canadensis*	PT	north-central PA (Tioga Co.)
Delmarva Peninsula fox squirrel	*Sciurus niger cinereus*	E	mature forests of southeastern PA (Delaware and Chester Co.)
Eastern cougar	*Felis concolor couguar*	E	state-wide
Grey wolf	*Canis lupus*	E	state-wide
MOLLUSKS			
Fanshell*	*Cyprogenia stegaria*	E	Ohio River drainage
Orange pimpleback*	*Plethobasus striatus*	E	Ohio River drainage
Pink mucket pearly mussel*	*Lampsilis abrupta*	E	Ohio River drainage
Ring pink mussel*	*Obovaria retusa*	E	Ohio River drainage
Rough pigtoe*	*Pleurobema plenum*	E	Ohio River drainage
INSECTS			
American burying beetle	*Nicrophorus americanus*	E	state-wide
Karner blue butterfly	*Lycaeides melissa samuelis*	E	pine barrens, oak savannas (wild lupine habitat) (Wayne Co.)
Northeastern beach tiger beetle	*Cicindela dorsalis dorsalis*	T	along large rivers in southeastern PA
PLANTS			
Eastern prairie fringed orchid	*Platanthera leucophaea*	T	wet prairies, bogs (Crawford Co.)
Sensitive joint-vetch	*Aeschynomene virginica*	T	freshwater tidal marshes of Delaware river (Delaware and Philadelphia Co.)
Virginia spiraea*	*Spiraea virginiana*	T	along Youghiogheny River (Fayette Co.)
Smooth coneflower	*Echinacea laevigata*	E	serpentine barrens (Lancaster Co.)

Revised 10/19/00

* *It is possible that remnant populations of some of these species (indicated with an *) may still occur in Pennsylvania, however, there have been no confirmed sightings of these species for over 70 years.*

** *E = Endangered, T = Threatened, PT = Proposed Threatened*

The following is a partial list of additional species that no longer occur in Pennsylvania: moose, bison, wolverine, passenger pigeon, Bachman's sparrow, greater prairie-chicken, olive-sided flycatcher, Bewick's wren, eastern tiger salamander, blue pike, butterfly mussel, Diana fritillary butterfly, precious underwing moth, deertoe mussel, marbled underwing moth, cobblestone tiger beetle, mountain clubmoss, crested yellow orchid, red milkweed, American barberry, small white lady's-slipper, etc. etc.

U.S. FISH AND WILDLIFE SERVICE
315 SOUTH ALLEN ST., SUITE 322, STATE COLLEGE, PA 16801

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

L. William Pearce
Site Vice President

724-682-5234
Fax: 724-643-8069

September 8, 2003
L-03-084

Mr. Frederick G. Carlson
Director of Policy
Pennsylvania Department of Conservation and Natural Resources
P.O. Box 8767
Harrisburg, PA 17105-8767

Subject: Beaver Valley Power Station License Renewal Project
Request for Information and Concurrence
Threatened & Endangered Plant Species Assessment

Reference: Letter CNS-02-050, Julea B. Hovey, Constellation Nuclear Services, to Richard G. Sprenkle, Pennsylvania Department of Conservation and Natural Resources, June 28, 2002

Dear Mr. Carlson:

FirstEnergy Nuclear Operating Company (FENOC) is preparing an environmental report as part of our operating license renewal application (LRA) to the U.S. Nuclear Regulatory Commission (NRC) for the Beaver Valley Power Station (BVPS) Units 1 and 2. BVPS Units 1 and 2 have been in operation since 1976 and 1987, respectively. Successful renewal would provide the opportunity to operate the units for up to 20 years beyond the expiration of their current licenses in 2016 and 2027, respectively.

In correspondence to the Pennsylvania Department of Conservation and Natural Resources (DCNR) referenced above, FENOC's LRA consultant indicated that the LRA environmental review would include an assessment of potential impacts of BVPS license renewal on threatened, endangered, and candidate species. Since that time, FENOC has completed a preliminary draft of an assessment of potential impacts on plant species within DCNR's jurisdiction, which will be finalized and included in the LRA environmental report. Accordingly, FENOC is now requesting DCNR assistance in finalizing our assessment to provide additional assurance that it is accurate and complete. By contacting you at this time, FENOC believes that the effectiveness of forthcoming NRC interactions with your office, described in the following paragraph, will be enhanced.

The NRC, at 10 CFR 51.53(c)(3)(ii)(E), requires that license renewal applicants " . . . assess the impact of the proposed action {license renewal} on threatened and endangered species in accordance with the Endangered Species Act." Consistent with our corporate commitment to natural resource conservation, we have addressed in our assessment both federal species and species similarly designated by the Commonwealth of Pennsylvania. The NRC staff routinely interacts with other affected agencies in conducting their environmental review, which leads to preparation of a supplemental environmental impact statement (SEIS) for this licensing action. It is expected that the DCNR will be contacted regarding potential impact on species within its jurisdiction as part of this activity. The following paragraphs describe relevant aspects of the BVPS environmental setting considered in the LRA and a synopsis of FENOC's assessment of potential impacts of BVPS license renewal on plant species of interest.

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The BVPS site consists of approximately 450 acres on the south side of the Ohio River (New Cumberland Pool) at Shippingport, Beaver County, Pennsylvania (see Attachment 1, Figure 1). The intensively developed or maintained portion of the site, approximately 220 acres, is located on a gravel terrace adjacent to the river; the remainder of the site consists mostly of forested slopes.

Short segments of three transmission lines on and adjacent to the BVPS site and one transmission line extending 15.8 miles southeast from BVPS (Duquesne Light Company's Beaver Valley-Crescent Line 318) are also being addressed in the BVPS LRA environmental report (see Attachment 1, Figures 2 and 3). The latter transmission line corridor traverses primarily through forest and farmland. Based on review of National Wetland Inventory maps, wetlands on or adjacent to this corridor are limited to a small (2-acre) palustrine forested area at the span of Service Creek and possibly one or more very small strips of riparian emergent vegetation at the span of Raccoon Creek (Attachment 1, Figure 3). The transmission line segments being considered in the LRA environmental report have been in service since the mid-1980s.

Based on our preliminary draft assessment, summarized in Attachment 2, FENOC believes that extended operation and maintenance of BVPS and the transmission corridors considered in the LRA would have no significant impact on threatened or endangered plant species. Results of Pennsylvania Natural Diversity Inventory (PNDI) searches conducted at FENOC's request, which involved reviews by DCNR staff, indicate that license renewal would pose no conflicts with plant species of concern if it does not involve land-disturbing activity. FENOC has not identified any land disturbing activities that would be undertaken for license renewal, and both FENOC and Duquesne Light would continue to be subject to applicable regulatory controls for the period of extended operation. Neither FENOC nor Duquesne Light is aware of any adverse impact to any threatened, endangered, or candidate plant species from past or current operation of BVPS or these transmission lines.

FENOC respectfully requests that the DCNR (1) formally notify us of any additional concerns or relevant information regarding threatened, endangered, and candidate species pertinent to our preliminary draft assessment and (2), as appropriate, concur with the assessment. FENOC will evaluate any information you provide for inclusion in the assessment, and will include your response to this request in the final LRA environmental report submitted to the NRC. FENOC would appreciate receiving your response within 60 days of receipt to provide ample time to evaluate and incorporate your response into our LRA environmental report for submittal to the NRC.

Thank you for your assistance as we complete this important environmental assessment. Please address any comments or questions you may have to Mr. Mark Ackerman, License Renewal Project Manager, by telephone at (724) 682-7994, e-mail ackermanm@firstenergycorp.com, or at the letterhead address above.

Sincerely,

L. William Pearce
Site Vice President

Attachments: Project Maps (Attachment 1)
Preliminary Assessment (Attachment 2)

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Page 3

bc: G. DeCamp (CNS)
T. Grenci (CNS)
M. S. Ackerman (3 copies)
Central File

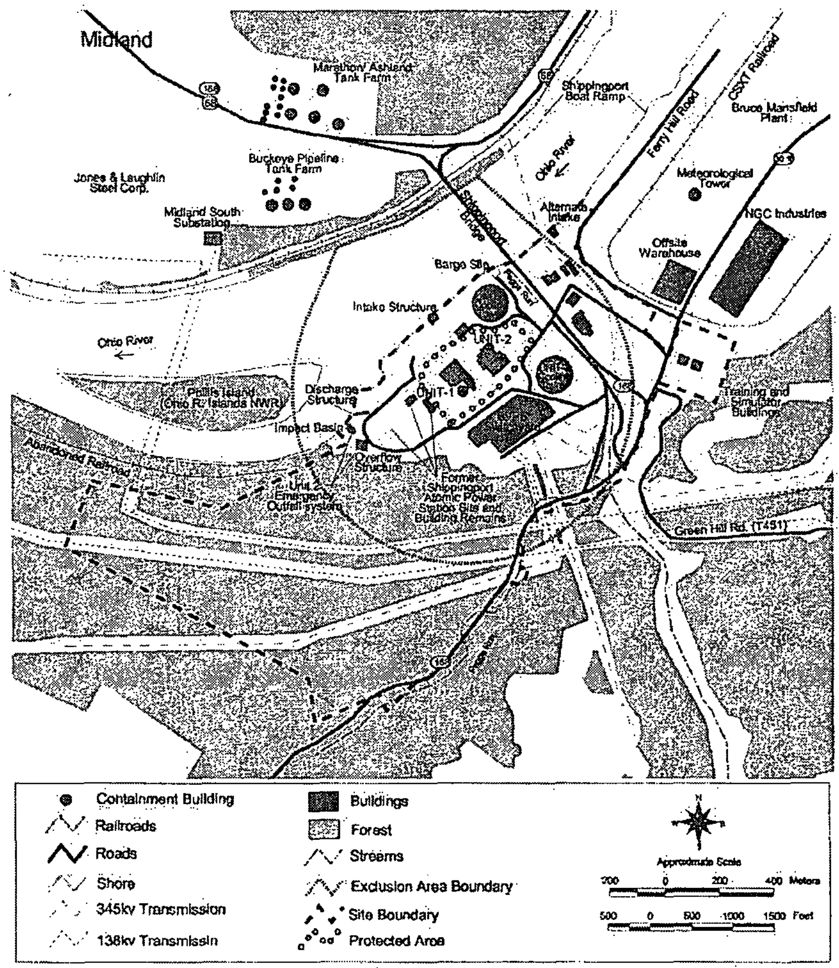
ATTACHMENT 1

PROJECT MAPS

BVPS LRA Environmental Review Att. 1-1
Project Maps

FIGURE 1

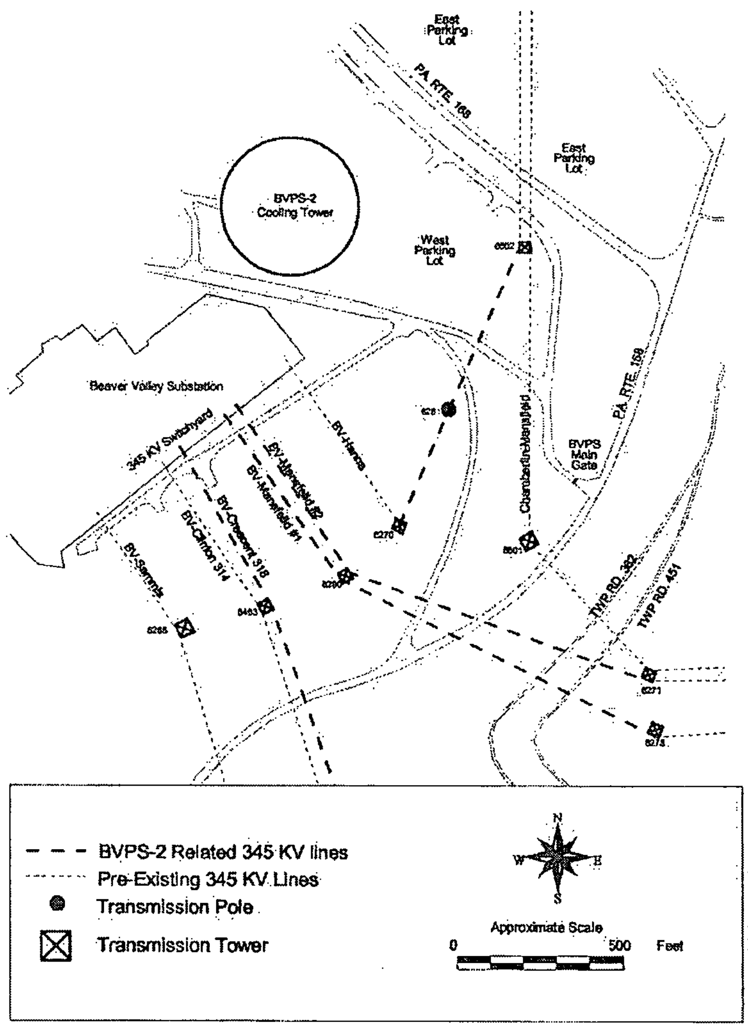
BEAVER VALLEY POWER STATION SITE MAP



BVPS LRA Environmental Review Project Maps Att. 1-2

FIGURE 2

345 kV RECONFIGURATIONS
FOR BEAVER VALLEY POWER STATION UNIT 2

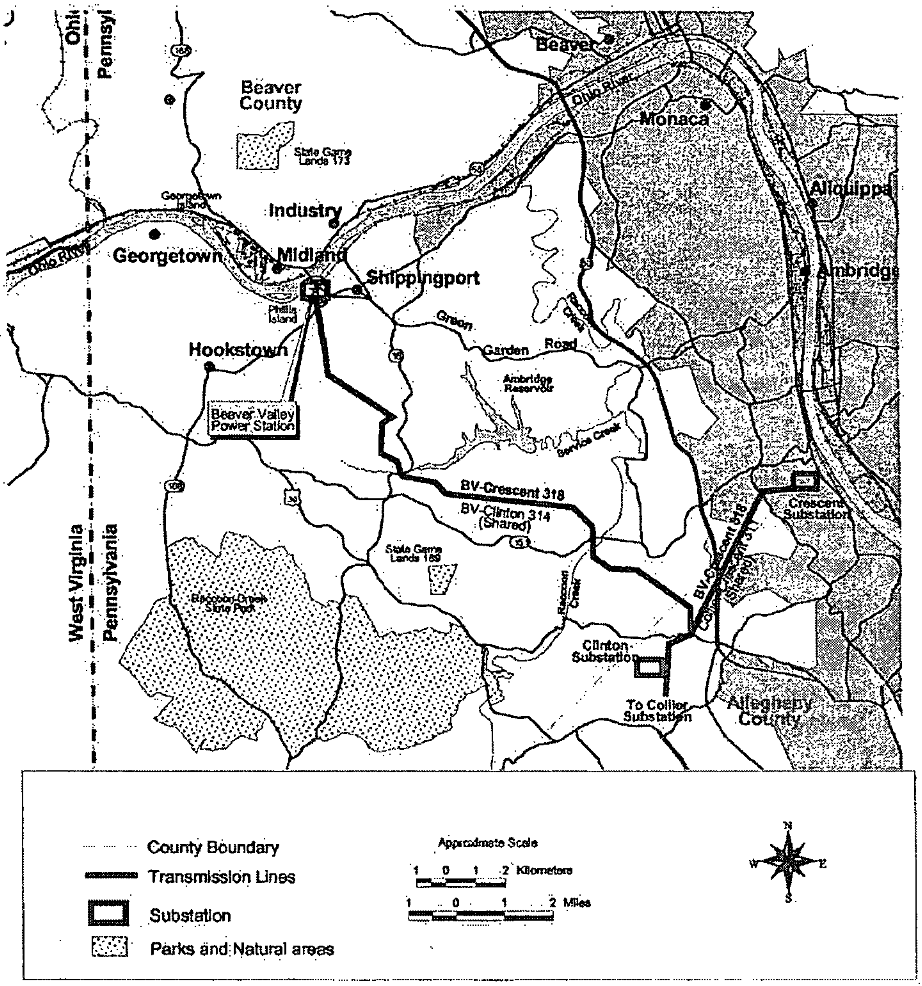


BVPS LRA Environmental Review
Project Maps

Att. 1-3

FIGURE 3

BEAVER VALLEY-CRESCENT LINE 318 CORRIDOR



BVPS LRA Environmental Review Att. 1-4
Project Maps

ATTACHMENT 2

PRELIMINARY ASSESSMENT

PENNSYLVANIA THREATENED, ENDANGERED, AND CANDIDATE SPECIES SUBJECT TO PENNSYLVANIA DEPARTMENT OF CONSERVATION AND NATURAL RESOURCES JURISDICTION OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL

TABLE 1

THREATENED, ENDANGERED, AND CANDIDATE SPECIES SUBJECT TO PENNSYLVANIA DEPARTMENT OF CONSERVATION AND NATURAL RESOURCES JURISDICTION OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL[a]

Common Name Scientific Name	U.S. Status[b]	PA Status[b]	Habitat/Occurrence
			Plants
Small whorled pogonia *Isotria medeoloides*	T	E	Nearly all populations occur in second growth or relatively mature forests; PA populations most abundant on dry east- or southeast-facing hillsides in mixed oak forest on rocky, somewhat acidic soils; only 2 occurrences in PA verified since 1980; known historical occurrence in southwestern PA only in Greene Co. (Ref. 1). Specifically reported as not observed during ecological surveys of the BVPS site in 1974-1975 (Ref. 2). Not identified by PNDI as potentially occurring in the vicinity of the BVPS site or Beaver Valley-Crescent Line 318 transmission line corridor (Ref. 3, Ref. 4, Ref. 5).
Eastern blue-eyed grass *Sisyrinchium atlanticum*	-	E	Found in moist to dry, sandy, open ground of fields and thin woods (Ref. 6, page 359; Ref. 7: page 843). Identified by PNDI as potentially occurring in the vicinity of Beaver Valley-Crescent Line 318 corridor (Ref. 4).
Tall larkspur *Delphinium exaltatum*	-	E	Found in dry, open southwestern-facing slopes with limestone soils, in rich shaded woods, and on rocky limestone bluffs (Ref. 6; Ref. 7, page 575). Historical occurrence in southeastern Beaver Co. and Allegheny Co., but no verified occurrences there since 1980 (Ref. 8). Identified by PNDI as potentially occurring in the general vicinity of Beaver Valley-Crescent Line 318 corridor (Ref. 4).
Purple rocket *Iodanthus pinnatifidus*	-	E	Found in moist alluvial woods and wooded slopes (Ref. 7, page 291). Identified by PNDI (Ref. 5) as potentially occurring in the vicinity of Beaver Valley-Crescent Line 318 corridor (2001 occurrence record) in a general area recognized for high biodiversity in Beaver County (Ref. 9).
Harbinger-of-spring *Erigenia bulbosa*	-	T	Found near seeps and spring heads on wooded slopes (Ref. 7, page 141). Identified by PNDI (Ref. 5) as potentially occurring in the vicinity of Beaver Valley-Crescent Line 318 corridor (1997 occurrence record) in a general area recognized for high biodiversity in Beaver County (Ref. 9).

Common Name Scientific Name	U.S. Status[b]	PA Status[b]	Habitat/Occurrence
Tall tick trefoil *Desmodium glabellum*	-	U	Found in dry, sandy woods (Ref. 7, page 404). Identified by PNDI as potentially occurring in the vicinity of the BVPS site and nearby portion of the Beaver Valley-Crescent Line 318 corridor (1974 occurrence record; Ref. 3, Ref. 5). Specifically reported as not observed in site reconnaissance survey in 2002 (Ref. 10).

a. Except as otherwise noted, tabulated species include (A) Federally designated threatened, endangered, and candidate plant species reported by the FWS for Pennsylvania (Ref. 11, Ref. 12) with known historical ranges that include the upper Ohio River or southwestern Pennsylvania, except those considered to be extirpated in PA, e.g., by the Pennsylvania Biological Survey (Ref. 13); and (B) the following species officially listed as endangered, threatened, or candidates for listing by the Commonwealth of Pennsylvania (Pennsylvania Code, Title 17, Chapter 45): plant species noted by the PNDI as potentially occurring in the vicinity of BVPS, including the Ohio River and Phillis Island, or the vicinity of the Beaver Valley-Crescent – 318 Transmission Line corridor (Ref. 3, Ref. 4, Ref. 5)

b. Status Codes: E = Endangered, T = Threatened, C = Candidate for Listing, U = Tentatively Undetermined

FWS = U.S. Fish and Wildlife Service
BVPS = Beaver Valley Power Station
PA = Pennsylvania
PNDI = Pennsylvania Natural Diversity Inventory

TABLE 2

SUMMARY IMPACT ASSESSMENT FOR THREATENED, ENDANGERED, AND CANDIDATE PLANT SPECIES SUBJECT TO PENNSYLVANIA DEPARTMENT OF CONSERVATIONAND NATURAL RESOURCES JURISDICTION OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL[a]

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
Small whorled pogonia *Isotria medeoloides* FT, PE	None to Low on BVPS site. Low on or near Beaver Valley – Crescent Line 318 corridor. Specifically reported as not observed during ecological surveys of the BVPS site in 1974-1975 (Ref. 2). Not reported in PNDI searches for either BVPS site (Ref. 3) or transmission corridor (Ref. 4, Ref. 5). None currently known from southwestern Pennsylvania.	Vegetation maintenance on BVPS site and transmission line corridor.	• FENOC and Duquesne Light maintenance practices on transmission corridors are limited to selective pruning or removal of trees that could interfere with the line and selective pruning or herbicide use to control incompatible vegetation. EPA-approved herbicides are selectively applied in accordance with manufacturer's label requirements by state-licensed applicators. • Similar vegetation practices to those employed on transmission line corridors are used on BVPS site to maintain cleared areas as needed for site security. • FENOC has not identified any land disturbing activities that would be undertaken for license renewal. • Both FENOC and Duquesne Light would continue to be subject to applicable regulatory controls for the period of extended operation. • Neither FENOC nor Duquesne Light is aware of any adverse impact to any threatened, endangered, or candidate plant species from past or current operation of BVPS or transmission lines being considered in the license renewal environmental review. • Forested areas within the Beaver Valley Crescent Line 318 corridor exist only at the bottom of some spanned ravines and valleys and along the corridor edge in some segments, reducing potential for disturbance of potentially compatible habitat. Impact Conclusion: SMALL

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
Eastern blue-eyed grass *Sisyrinchium atlanticum* PE Tall larkspur *Delphinium exaltatum* PE Purple rocket *Iodanthus pinnatifidus* PE Harbinger-of-spring *Erigenia bulbosa* PT	Low on BVPS site. Moderate to high on or near Beaver Valley-Crescent Line-318 corridor. PNDI searches indicate occurrence records for these species only in the vicinity of the transmission corridor (Ref. 3, Ref. 4, Ref 5); records for purple rocket and harbinger-of spring are recent (Ref. 5).	Same as above for all	• Same considerations as listed above for small whorled pogonia for all, plus the following additional considerations. • PNDI review for the Allegheny County portion of the Beaver Valley-Crescent Line 318 corridor, which identified occurrence records for Eastern blue-eyed grass and tall larkspur, concluded that that continued operation of the Beaver Valley-Crescent Line 318 corridor would pose no conflicts with these plant species (Ref. 4). • PNDI review for the Beaver County portion of the Beaver Valley-Crescent Line 318 corridor, which identified occurrence records for purple rocket and harbinger of spring, indicates that license renewal would pose no conflict with this plant species if it does not involve land-disturbing activity (Ref. 5). Impact Conclusion: SMALL

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
Tall tick trefoil *Desmodium glabellum* PU	Low on main portion of BVPS site. *Specifically* reported as not observed in site reconnaissance survey in 2002 (Ref. 10). Moderate on or near Beaver Valley-Crescent Line 318 corridor, including segment on BVPS site. PNDI searches for BVPS site (Ref. 3) and Beaver County portion of Beaver Valley-Crescent Line 318 corridor (Ref. 5) indicate potential presence (1974 occurrence record).	Same as above	• Same considerations as listed above for small whorled pogonia. • PNDI review for the Beaver County portion of the Beaver Valley-Crescent Line 318 corridor, which identified an occurrence record for tall tick-trefoil, indicates that license renewal would pose no conflict with this plant species if it does not involve land-disturbing activity (Ref. 5). Impact Conclusion: SMALL

a. Tabulated species, status, and occurrence potential based on information presented in Table 1.
b. Status Codes: FE = Federal Endangered, FT = Federal Threatened, FC = Federal Candidate for Listing, PE = PA Endangered, PT = PA Threatened, PC = PA Candidate for Listing, PU = PA Tentatively Undetermined.
c. Additional considerations include controls established for impact initiators, industry and plant experience related to potential impacts, information received from regulatory agencies, and other relevant factors.

FENOC = FirstEnergy Nuclear Operating Company
BVPS = Beaver Valley Power Station
PA = Pennsylvania
PNDI = Pennsylvania Natural Diversity Inventory

REFERENCES

1. Pennsylvania Department of Conservation and Natural Resources. *Small Whorled Pogonia* *Isotria medeoloides Raf.* http://www.dcnr.state.pa.us/wrcf/spog.htm. Accessed October 12, 2002.

2. Duquesne Light Company. *Beaver Valley Power Station Unit 2 Environmental Report – Operating License Stage.* Amendment 6. May 1984.

3. Pennsylvania Natural Diversity Inventory. Results for PNDI Search N100081. May 31, 2002.

4. Pennsylvania Natural Diversity Inventory. Results for PNDI Searches N105492, N105493, and N105494, conducted September 4, 2002; "Potential Conflict" Response Forms, September 24, 2002.

5. Pennsylvania Natural Diversity Inventory. Letter from Autumn E. Sabo, Pennsylvania Natural Diversity Inventory, to Greg DeCamp, Constellation Nuclear Services. "Bureau of Forestry, Pennsylvania Natural Diversity Inventory Search FirstEnergy Nuclear Operating Company Transmission Lines, Shippingport Borough, Beaver County, PA – PNDI #013501". March 18, 2003.

6. Haywood, M.J. and P.T. Monk. *Wildflowers of Pennsylvania.* Botanical Society of Western Pennsylvania. Venture Graphics. 2001.

7. Rhoads, A.F. and T.A. Block. *The Plants of Pennsylvania: An Illustrated Manual.* Univ. of Pennsylvania Press. Philadelphia. 2000.

8. Pennsylvania Department of Conservation and Natural Resources. *Tall Larkspur* *Delphinium exaltatum Ait.* http://www.dcnr.state.pa.us/wrcf/tlark.htm. Accessed October 12, 2002.

9. Beaver County Planning Commission. *Horizons – Planning for the 21st Century: A Comprehensive Plan for Beaver County.* December 1999.

10. Beak Consultants Inc. *Plant Community Characterization Study for the Beaver Valley Power Station Site, Shippingport, Pennsylvania.* Lancaster, New York. October 2002.

11. U.S. Fish and Wildlife Service. *Threatened and Endangered Species System (TESS) Listings by State and Territory as of 10/12/2002 - Pennsylvania.* http://ecos.fws.gov/servlet/TESSWebpageUsaLists?state=PA. Accessed October 13, 2002.

12. U.S. Fish and Wildlife Service. *Threatened and Endangered Species System (TESS) Candidate Species as of 10/12/2002.* http://ecos.fws.gov/servlet/TESSWebpageNonlisted?listings=0&type=C. Accessed October 13, 2002.

13. Pennsylvania Biological Survey. *Inventory and Monitoring of Biological Resources in Pennsylvania; Proceedings of the First Conference of the Pennsylvania Biological Survey.* 1998. http://www.dickinson.edu/prorg/pabs/pabs_main.htm. Accessed October 13, 2002.

Pennsylvania Natural Diversity Inventory

Scientific information and expertise for the conservation of Pennsylvania's native biological diversity

October 3, 2003

Fax 717-772-0271
717-772-0258

Bureau of Forestry

L. William Pearce
FENOC
Beaver Valley Power Station
RT 168, PO Box 4
Shippingport, PA 15077-0004

Re: Pennsylvania Natural Diversity Inventory Review of the Proposed Beaver Valley Power Station License Renewal Project **UPDATE** **PER NO: 15055**

Dear Mr. Pearce:

In response to your request on September 8, 2003 to update the above-mentioned project, we have reviewed the area using the Pennsylvania Natural Diversity Inventory (PNDI) information system. PNDI records remain consistent with the findings of the letter issued March 18, 2003 to Greg DeCamp of the Constellation Nuclear Services. *Iodanthus pinnatifidus* (purple rocket), *Erigenia bulbosa* (harbinger-of-spring), and *Desmodium glabellum* (tall tick-trefoil) grows along the transmission lines that are represented here.

As previously state in a correspondence to Mike Yeck dated December 17, 2002, prior to beginning any additional site development you should contact our office. Since the requested permit is only to allow the continued use of the lines and BVPS Units 1 and 2, no additional coordination is required with our office until earth disturbance is planned.

PNDI is the environmental review function for the Pennsylvania Natural Heritage Program, and uses a site specific information system that describes significant natural resources of Pennsylvania. This system includes data descriptive of plant and animal species of special concern, exemplary natural communities and unique geological features. PNHP is a cooperative project of the Department of Conservation and Natural Resources, The Nature Conservancy and the Western Pennsylvania Conservancy. This response represents the most up-to-date summary of the PNDI data files and is good for one year. An absence of recorded information does not necessarily imply actual conditions on-site. A field survey of any site may reveal previously unreported populations.

Western Pennsylvania Conservancy
209 Fourth Ave.
Pittsburgh, PA 15222
(412)288-2777
www.paconserve.org

Pennsylvania Dept. of Conservation and Natural Resources
Bureau of Forestry
P O Box 8552
Harrisburg, PA 17105 8552
(717)787-3444
www.dcnr.state.pa.us

The Nature Conservancy
208 Airport Drive
Middletown, PA 17057
(717)948-3962
www.tnc.org

L. William Pearce 2 October 3, 2003

Feel free to phone our office if you have questions concerning this response or the PNDI system, and please refer to the P.E.R. Reference Number at the top of the letter in future correspondence concerning this project.

Sincerely,

Justin P. Newell
Environmental Review Specialist

Cc: file
Frederick Carlson

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

L. William Pearce
Site Vice President

724-682-5234
Fax: 724-643-8069

September 8, 2003
L-03-083

Mr. James R. Leigey
Wildlife Impact Review Coordinator
Pennsylvania Game Commission
2001 Elmerton Avenue
Harrisburg, PA 17110-9797

Subject: Beaver Valley Power Station License Renewal Project
Request for Information and Concurrence - Threatened & Endangered Species

References: (a) Letter CNS-02-050, Julea B. Hovey, Constellation Nuclear Services, to Vernon R. Ross, Pennsylvania Game Commission, June 28, 2002
(b) Letter, James R. Leigey, Pennsylvania Game Commission, to Mark S. Ackerman, Beaver Valley Power Station, July 25, 2002.

Dear Mr. Leigey:

FirstEnergy Nuclear Operating Company (FENOC) is preparing an environmental report as part of our operating license renewal application (LRA) to the U.S. Nuclear Regulatory Commission (NRC) for the Beaver Valley Power Station (BVPS) Units 1 and 2. BVPS Units 1 and 2 have been in operation since 1976 and 1987, respectively. Successful renewal would provide the opportunity to operate the units for up to 20 years beyond the expiration of their current licenses in 2016 and 2027, respectively.

In correspondence to the Pennsylvania Game Commission referenced above, FENOC's LRA consultant indicated that the LRA environmental review would include an assessment of potential impacts of BVPS license renewal on threatened, endangered, and candidate species. Since that time, FENOC has completed a preliminary draft of an assessment of potential impacts on species within Pennsylvania Game Commission jurisdiction, which will be finalized and included in the LRA environmental report. Accordingly, FENOC is now requesting your assistance in finalizing our assessment to provide additional assurance that it is accurate and complete. By contacting you at this time, FENOC believes that the effectiveness of forthcoming NRC interactions with your office, described in the following paragraph, will be enhanced.

The NRC, at 10 CFR 51.53(c)(3)(ii)(E), requires that license renewal applicants " . . . assess the impact of the proposed action {license renewal} on threatened and endangered species in accordance with the Endangered Species Act." Consistent with our corporate commitment to natural resource conservation, we have addressed in our assessment both federal species and species similarly designated by the Commonwealth of Pennsylvania. The NRC staff routinely interacts with other affected agencies in conducting their environmental review, which leads to preparation of a supplemental environmental impact statement (SEIS) for this licensing action. It is expected that the Pennsylvania Game Commission will be contacted regarding potential impact on species within its jurisdiction as part of this activity. The following paragraphs

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Page 2

describe relevant aspects of the BVPS environmental setting considered in the LRA and a synopsis of FENOC's assessment of potential impacts of BVPS license renewal on species of interest.

The BVPS site consists of approximately 450 acres on the south side of the Ohio River (New Cumberland Pool) at Shippingport, Beaver County, Pennsylvania (see Attachment 1, Figure 1). The intensively developed or maintained portion of the site, approximately 220 acres, is located on a gravel terrace adjacent to the river; the remainder of the site consists mostly of forested slopes. BVPS employs a closed-cycle cooling system (cooling towers), and withdraws cooling water, primarily makeup water for this system, from the Ohio River at the Intake Structure. Cooling water, primarily cooling tower blowdown, is discharged to the Ohio River at the Discharge Structure and Emergency Overflow Structure and Impact Basin, along with small volumes of treated wastewater, in accordance with provisions of NPDES Permit PA0025615.

Short segments of three transmission lines on and adjacent to the BVPS site and one transmission line extending 15.8 miles southeast from BVPS (Duquesne Light Company's Beaver Valley-Crescent Line 318) are also being addressed in the BVPS LRA environmental report (see Attachment 1, Figures 2 and 3). The latter transmission line corridor traverses primarily through forest and farmland. Based on review of National Wetland Inventory maps, wetlands on or adjacent to this corridor are limited to a small (2-acre) palustrine forested area at the span of Service Creek and possibly one or more very small strips of riparian emergent vegetation at the span of Raccoon Creek (Attachment 1, Figure 3). The transmission line segments being considered in the LRA environmental report have been in service since the mid-1980s.

Our preliminary draft assessment, summarized in Attachment 2, specifically considers the information you provided in your July 25, 2002 letter [Reference (b), above], which addressed bird and mammal species in the BVPS site vicinity. Based on our assessment, FENOC believes that extended operation and maintenance of both BVPS and the associated transmission corridors being considered in the LRA would have no significant impact on threatened, endangered, or candidate species under Pennsylvania Game Commission jurisdiction. FENOC has not identified any land disturbing activities that would be undertaken for license renewal, and both FENOC and Duquesne Light would continue to be subject to applicable regulatory controls for the period of extended operation. Neither FENOC nor Duquesne Light is aware of any adverse impact to any threatened, endangered, or candidate bird or mammal species from past or current operation of BVPS or these transmission lines.

FENOC respectfully requests that the Pennsylvania Game Commission (1) formally notify us of any concerns or additional relevant information regarding threatened, endangered, and candidate species pertinent to our preliminary draft assessment and (2), as appropriate, concur with the assessment. FENOC will evaluate any information you provide for inclusion in the assessment, and will include your response to this request in the final LRA environmental report submitted to the NRC. FENOC would appreciate receiving your response within 60 days of receipt to provide ample time to evaluate and incorporate your response into our LRA environmental report for submittal to the NRC.

Thank you for your assistance as we complete this important environmental assessment. Please address any comments or questions you may have to Mr. Mark Ackerman, License

L-03-083
Page 3

Renewal Project Manager, by telephone at (724) 682-7994, e-mail ackermanm@firstenergycorp.com, or at the letterhead address above.

Sincerely,

L. William Pearce
Site Vice President

Attachments: Project Maps (Attachment 1)
Preliminary Assessment (Attachment 2)

L-03-083
Page 4

bc: G. DeCamp (CNS)
T. Grenci (CNS)
M. S. Ackerman (3 copies)
Central File

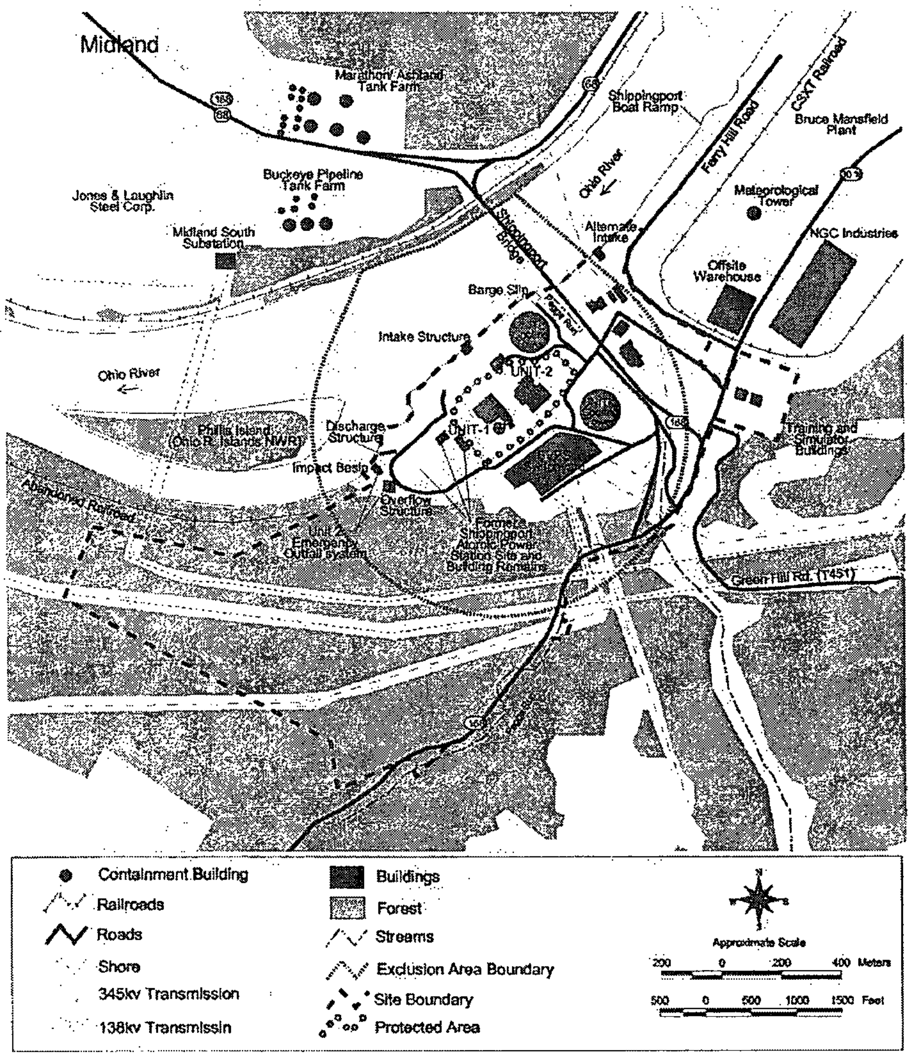
ATTACHMENT 1

PROJECT MAPS

BVPS LRA Environmental Review Att. 1-1
Project Maps

FIGURE 1

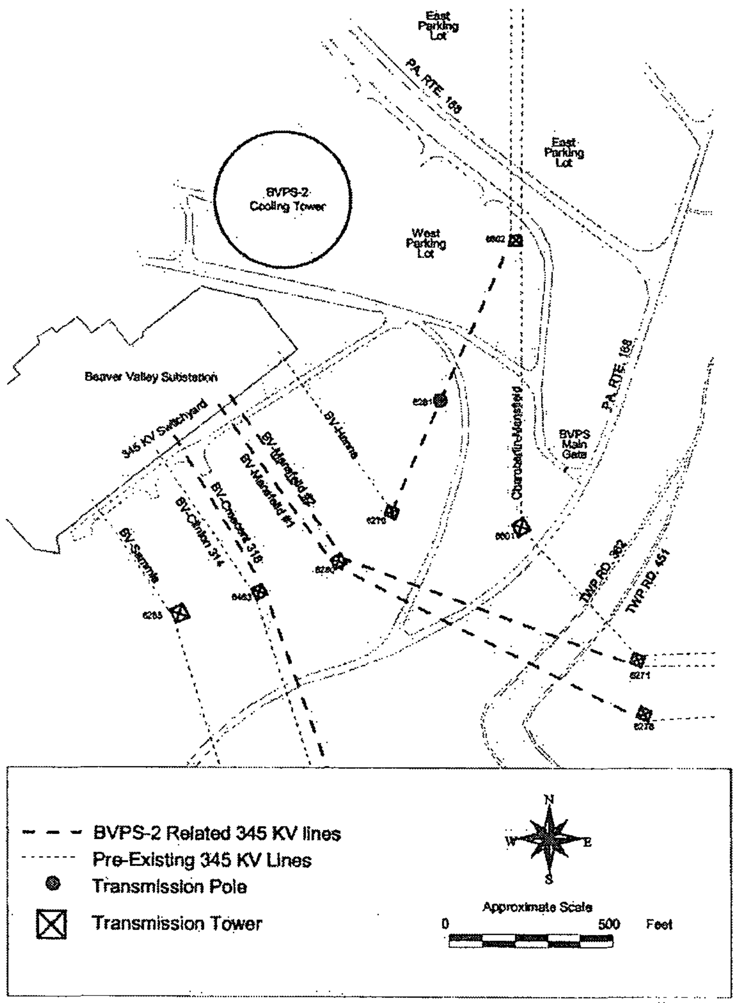
BEAVER VALLEY POWER STATION SITE MAP



BVPS LRA Environmental Review Project Maps	Att. 1-2

FIGURE 2

**345 kV RECONFIGURATIONS
FOR BEAVER VALLEY POWER STATION UNIT 2**

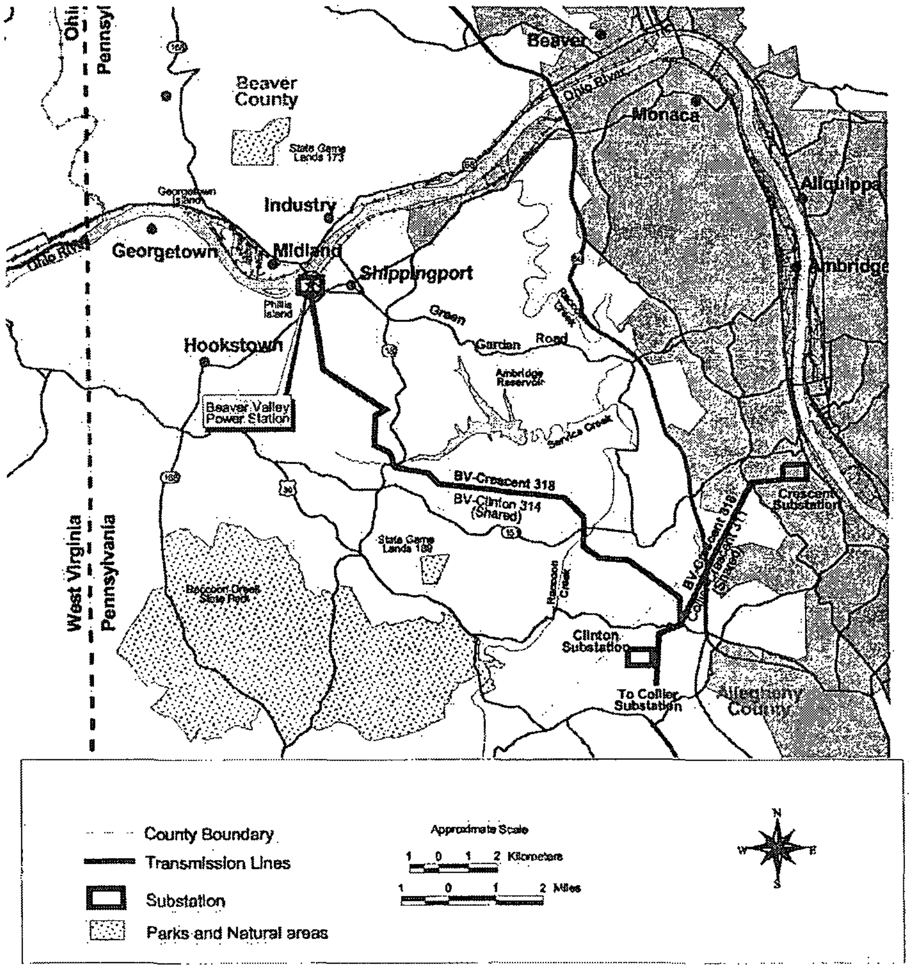


BVPS LRA Environmental Review
Project Maps

Att. 1-3

FIGURE 3

BEAVER VALLEY-CRESCENT LINE 318 CORRIDOR



BVPS LRA Environmental Review Att. 1-4
Project Maps

ATTACHMENT 2

PRELIMINARY ASSESSMENT

PENNSYLVANIA THREATENED, ENDANGERED, AND CANDIDATE SPECIES SUBJECT TO PENNSYLVANIA GAME COMMISSION JURISDICTION OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL

TABLE 1

PENNSYLVANIA THREATENED, ENDANGERED, AND CANDIDATE SPECIES SUBJECT TO PENNSYLVANIA GAME COMMISSION JURISDICTION OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL[a]

Common Name Scientific Name	U.S. Status[b]	PA Status[b]	Habitat/Occurrence
			Birds
Bald Eagle *Haliaeetus leucocephalus*	T	E	Thrives around bodies of water where adequate food exists and human intrusions and disturbance is limited. PA populations are recovering from effects of the pesticide DDT, the primary reason for the population decline. From 1997 to 1999, the PA nesting population more than doubled to 43 pairs; however, no nesting has been reported in Beaver or Allegheny Counties as of 1999 (Ref. 1). Individuals are occasionally observed along the Ohio River at BVPS. Not identified by PNDI as a potential conflict with respect to the BVPS site vicinity or Beaver Valley-Crescent Line 318 transmission line corridor (Ref. 2; Ref. 3, Ref. 4). PA Game Commission (Ref. 5) indicates that, except for occasional transient individuals, BVPS is not located in an area that is habitat for an endangered or threatened species of bird under their jurisdiction.
Peregrine Falcon *Falco peregrinus*	-	E	Historically, nested on high cliffs overlooking river systems. Current nesting sites include high bridges and buildings in cities, a result of recovery efforts that led to de-listing of this species at the federal level. PA populations are slowly recovering from effects of the pesticide DDT, the primary reason for the population decline. Successfully nesting at several sites in PA, including Gulf Tower in downtown Pittsburgh, Allegheny Co. (Ref. 6). Not identified by PNDI as a potential conflict with respect to the BVPS site vicinity or Beaver Valley-Crescent Line 318 transmission line corridor (Ref. 2; Ref. 3, ref. 4). PA Game Commission (Ref. 5) indicates that, except for occasional transient individuals, BVPS is not located in an area that is habitat for an endangered or threatened species of bird under their jurisdiction.

Common Name Scientific Name	U.S. Status[b]	PA Status[b]	Habitat/Occurrence
Short-eared Owl *Asio flammeus*	-	E	Nests on the ground in open country, including reclaimed strip mines; open, uncut grassy fields; large meadows; airports; and, occasionally, marshes. Nesting habitat is extremely limited in PA; intensive agricultural practices render habitats unsuitable. Recent nesting documented on reclaimed strip mines in western PA, including Allegheny Co. (Ref. 7). Not identified by PNDI as a potential conflict with respect to the BVPS site vicinity or Beaver Valley-Crescent Line 318 transmission line corridor (Ref. 2; Ref. 3; Ref. 4). PA Game Commission (Ref. 5) indicates that, except for occasional transient individuals, BVPS is not located in an area that is habitat for an endangered or threatened species of bird under their jurisdiction.
			Mammals
Indiana bat *Myotis sodalis*	E	E	Hibernates in winter in communal caves, usually with standing or flowing water, of which nine are known in PA (none in Beaver and Allegheny Counties). Known summer habitat includes maternal colonies behind flaking bark on dead or dying trees along stream or river corridors, and upland forests. Primary threat is disturbance to hibernating populations and hibernation sites (Ref. 8). Not identified by PNDI as a potential conflict with respect to the BVPS site vicinity or Beaver Valley-Crescent Line 318 transmission line corridor (Ref. 2; Ref. 3, Ref. 4). PA Game Commission (Ref. 5) indicates that, except for occasional transient individuals, BVPS is not located in an area that is habitat for an endangered or threatened species of mammal under their jurisdiction.

a. Tabulated species include officially listed as endangered, threatened, or candidates for listing by the Commonwealth of Pennsylvania under Pennsylvania Code, Title 58, Chapter 33: bird and mammal species indicated by the Pennsylvania Game Commission as having recent records of nesting (birds), hibernals (bats), or occurrences (other mammals) in Beaver County or Allegheny County, PA (Ref. 9).

b. Status Codes: E = Endangered, T = Threatened

FENOC = FirstEnergy Nuclear Operating Company
BVPS = Beaver Valley Power Station
PA = Pennsylvania
PNDI = Pennsylvania Natural Diversity Inventory

TABLE 2

SUMMARY IMPACT ASSESSMENT FOR THREATENED, ENDANGERED, AND CANDIDATE SPECIES SUBJECT TO PENNSYLVANIA GAME COMMISSION JURISDICTION OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL[a]

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
Birds			
Bald Eagle *Haliaeetus leucocephalus* FT, PE	High for transient or foraging individuals. Occasional individuals are observed along the Ohio River at the BVPS site. None to Low for future nesting on or near BVPS site considering industrial development and human activity. Low to Moderate for future nesting along Beaver Valley-Crescent Line 318 transmission corridor considering undeveloped areas near Ambridge Reservoir.	Collision with cooling towers or transmission lines.	• Surveys of bird collisions at the BVPS-1 cooling tower in spring and fall from 1974 through 1978 found a total of only 27 dead birds (26 passerines and one rail) Ref. 10, Page 5.1-21). • FirstEnergy and Duquesne Light are not aware of any reports of impact or electrocutions of these species associated with Beaver Valley-Crescent Line 318 or transmission line relocations addressed in the BVPS license renewal environmental review. • Results of PNDI searches (Ref. 2, Ref. 3, Ref. 4) conducted at FENOC's request have not identified these or other listed or candidate species under PA Game Commission jurisdiction as potential conflicts with BVPS or transmission line operation. • PA Game Commission (Ref. 5) indicates that, except for occasional transient individuals, BVPS is not located in an area that is habitat for an endangered or threatened bird under their jurisdiction, nor are any long-term adverse impacts to associated critical or unique habitats anticipated from BVPS operation. Impact Conclusion: SMALL

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
Peregrine Falcon *Falco peregrinus* PE	Moderate for transient or foraging individuals. None to Low for nesting considering habitat availability.	Same as bald eagle.	Same as bald eagle.
Short-eared Owl *Asio flammeus* PE	Moderate for transient or foraging individuals. None for nesting on BVPS site. Low for nesting on or near Beaver Valley-Crescent Line 318 transmission corridor considering habitat availability.	Same as bald eagle.	Same as bald eagle.
		Mammals	
Indiana bat *Myotis sodalis* FE, PE	None for hibernating colonies. Low for maternal colonies on BVPS site. Not collected or observed in 1974-75 ecological surveys of BVPS site (Ref. 9, Table 2.2-16). Low for maternal colonies in trees bordering Beaver Valley-Crescent Line 318 transmission corridor.	Removal of maternal colony trees bordering transmission corridor.	• Corridor maintenance practices limit removal of mature trees to those that could interfere with transmission lines. • Streams along corridor are frequently in relatively deep narrow valleys that are spanned, reducing the necessity to clear riparian trees. • Results of PNDI searches (Ref. 2, Ref. 3, Ref. 4) conducted at FENOC's request have not identified this or other mammal species under PA Game Commission jurisdiction as potential conflicts with BVPS or transmission line operation. • PA Game Commission (Ref. 5) indicates that, except for occasional transient individuals, BVPS is not located in an area that is habitat for an endangered or threatened mammal under their jurisdiction, nor are any long-term adverse impacts to associated critical or unique habitats anticipated from BVPS operation. *Impact Conclusion:* SMALL

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	*Additional Impact Considerations and Conclusions*[c]

a. Tabulated species, status, and occurrence potential based on information presented in Table 1.
b. Status Codes: FE = Federal Endangered, FT = Federal Threatened, FC = Federal Candidate for Listing, PE = PA Endangered, PT = PA Threatened, PC = PA Candidate for Listing.
c. Additional considerations include controls established for impact initiators, industry and plant experience related to potential impacts, information received from regulatory agencies, and other relevant factors.

FENOC = FirstEnergy Nuclear Operating Company
BVPS = Beaver Valley Power Station
PA = Pennsylvania
PNDI = Pennsylvania Natural Diversity Inventory

REFERENCES

1. Pennsylvania Game Commission. *Bald Eagle (Haliaeetus leucocephalus)*. http://sites.state.pa.us/PA_Exec/PGC/eagle/profile.htm. Accessed October 12, 2002.

2. Pennsylvania Natural Diversity Inventory. Results for PNDI Search N100081. May 31, 2002.

3. Pennsylvania Natural Diversity Inventory. Results for PNDI Searches N105492, N105493, and N105494, conducted September 4, 2002; "Potential Conflict" Response Forms, September 24, 2002.

4. Pennsylvania Natural Diversity Inventory. Letter from Autumn E. Sabo, Pennsylvania Natural Diversity Inventory, to Greg DeCamp, Constellation Nuclear Services. "Bureau of Forestry, Pennsylvania Natural Diversity Inventory Search FirstEnergy Nuclear Operating Company Transmission Lines, Shippingport Borough, Beaver County, PA – PNDI #013501". March 18, 2003.

5. Pennsylvania Game Commission. Letter from James R. Leigey, Pennsylvania Game Commission, to Mark S. Ackerman, FENOC. "Beaver Valley Power Station License Renewal Project, Shippingport, Beaver County, PA". July 25, 2002.

6. Pennsylvania Game Commission. *Peregine Falcon (Falco peregrinus)*. http://sites.state.pa.us/PA_Exec/PGC/falcon/profile.htm. Accessed October 12, 2002.

7. Pennsylvania Game Commission. *Short-eared Owl (Asio flammeus)*. http://sites.state.pa.us/PA_Exec/PGC/owl/profile.htm. Accessed October 12, 2002.

8. Pennsylvania Game Commission. *Indiana Bat (Myotis sodalis)*. http://sites.state.pa.us/PA_Exec/PGC/bat/indiana/profile.htm. Accessed October 12, 2002.

9. Pennsylvania Game Commission. *Endangered and Threatened Species*. http://sites.state.pa.us/PA_Exec/PGC/endangered/index.htm. Accessed October 12, 2002.

10. Duquesne Light Company. *Beaver Valley Power Station Unit 2 Environmental Report – Operating License Stage*. Amendment 6. May 1984.

BVPS LRA Preliminary Assessment
PA Game Commission Threatened & Endangered Species

Att. 2-6

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA GAME COMMISSION
2001 ELMERTON AVENUE, HARRISBURG, PA 17110-9797

October 9, 2003

Mr. Mark S. Ackerman
FirstEnergy Nuclear Operating Company
BVPS License Renewal Project Manager
Beaver Valley Power Station (Mail Stop ISI)
PO Box 4, Route 168W
Shippensport, PA 15077-0004

In re: Beaver Valley Power Station
License Renewal Project
Shippensport, Beaver County, PA

Dear Mr. Ackerman:

This is our response to your letter of September 8, 2003, requesting information and a response about referenced project.

We have completed an office review and determined that except for occasional transient individuals, this project should not affect endangered or threatened species of bird or mammal recognized by the Pennsylvania Game Commission nor do we anticipate any adverse impacts to any critical or unique habitats.

Based on our office review only, we have no objections to the renewal of your license, but should project plans change, or if additional information becomes available, this determination could be re-evaluated.

Please direct any questions or comments to me at 717-783-5957.

Very truly yours,

James R. Leigey

James R. Leigey
Wildlife Impact Review Coordinator
Division of Environmental Planning
And Habitat Protection
Bureau of Land Management

JJK/pfb

Cc: File
SW Reg., Dir., Hough Attn: Smith

ADMINISTRATIVE BUREAUS:
PERSONNEL: 717-787-7836 ADMINISTRATION: 717-787-5670 AUTOMOTIVE AND PROCUREMENT DIVISION: 717-787-6594
LICENSE DIVISION: 717-787-2084 WILDLIFE MANAGEMENT: 717-787-5529 INFORMATION & EDUCATION: 717-787-6286 LAW ENFORCEMENT: 717-787-5740
LAND MANAGEMENT: 717-787-6818 REAL ESTATE DIVISION: 717-787-6568 AUTOMATED TECHNOLOGY SYSTEMS: 717-787-4076 FAX: 717-772-2411
WWW.PGC.STATE.PA.US

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

L. William Pearce
Site Vice President

724-682-5234
Fax: 724-643-8069

September 8, 2003
L-03-085

Mr. John A. Arway
Chief, Division of Environmental Services
Pennsylvania Fish and Boat Commission
450 Robinson Lane
Bellefonte, PA 16823

Subject: Beaver Valley Power Station License Renewal Project
Request for Information and Concurrence - Threatened & Endangered Species

References:
(a) Letter CNS-02-050, Julea B. Hovey, Constellation Nuclear Services, to Peter A. Colangelo, Pennsylvania Fish and Boat Commission, June 28, 2002.
(b) Letter SIR #9555, John A. Arway, Pennsylvania Fish and Boat Commission, to Michael D Banko III, FENOC, September 16, 2002.
(c) Letter SIR #11240, John A. Arway, Pennsylvania Fish and Boat Commission, to Michael D. Banko III, FENOC, February 26, 2003.

Dear Mr. Arway:

FirstEnergy Nuclear Operating Company (FENOC) is preparing an environmental report as part of our operating license renewal application (LRA) to the U.S. Nuclear Regulatory Commission (NRC) for the Beaver Valley Power Station (BVPS) Units 1 and 2. BVPS Units 1 and 2 have been in operation since 1976 and 1987, respectively. Successful renewal would provide the opportunity to operate the units for up to 20 years beyond the expiration of their current licenses in 2016 and 2027, respectively.

In correspondence to the Pennsylvania Fish and Boat Commission (PFBC) referenced above, FENOC's LRA consultant indicated that the LRA environmental review would include an assessment of potential impacts of BVPS license renewal on threatened, endangered, and candidate species. Since that time, FENOC has completed a preliminary draft of an assessment of potential impacts on species within PFBC's jurisdiction, which will be finalized and included in the LRA environmental report. Accordingly, FENOC is now requesting PFBC assistance in finalizing our assessment to provide additional assurance that it is accurate and complete. By contacting you at this time, FENOC believes that the effectiveness of forthcoming NRC interactions with your office, described in the following paragraph, will be enhanced.

The NRC, at 10 CFR 51.53(c)(3)(ii)(E), requires that license renewal applicants "assess the impact of the proposed action {license renewal} on threatened and endangered species in accordance with the Endangered Species Act." Consistent with our corporate commitment to natural resource conservation, we have addressed in our assessment both federal species and species similarly designated by the Commonwealth of Pennsylvania. The NRC staff routinely interacts with other affected agencies in conducting their environmental review, which leads to preparation of a supplemental environmental impact statement (SEIS) for this licensing action.

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Page 2

It is expected that the PFBC will be contacted regarding potential impact on species within its jurisdiction as part of this activity. The following paragraphs describe relevant aspects of the BVPS environmental setting considered in the LRA and a synopsis of FENOC's assessment of potential impacts of BVPS license renewal on species of interest.

The BVPS site consists of approximately 450 acres on the south side of the Ohio River (New Cumberland Pool) at Shippingport, Beaver County, Pennsylvania (see Attachment 1, Figure 1). The intensively developed or maintained portion of the site, approximately 220 acres, is located on a gravel terrace adjacent to the river; the remainder of the site consists mostly of forested slopes. BVPS employs a closed-cycle cooling system (cooling towers), and withdraws cooling water, primarily makeup water for this system, from the Ohio River at the Intake Structure. Cooling water, primarily cooling tower blowdown, is discharged to the Ohio River at the Discharge Structure and Emergency Overflow Structure and Impact Basin, along with small volumes of treated wastewater, in accordance with provisions of NPDES Permit PA0025615.

Short segments of three transmission lines on and adjacent to the BVPS site and one transmission line extending 15.8 miles southeast from BVPS (Duquesne Light Company's Beaver Valley-Crescent Line 318) are also being addressed in the BVPS LRA environmental report (see Attachment 1, Figures 2 and 3). The latter transmission line corridor traverses primarily through forest and farmland. Based on review of National Wetland Inventory maps, wetlands on or adjacent to this corridor are limited to a small (2-acre) palustrine forested area at the span of Service Creek and possibly one or more very small strips of riparian emergent vegetation at the span of Raccoon Creek (Attachment 1, Figure 3). The transmission line segments being considered in the LRA environmental report have been in service since the mid-1980s.

Our preliminary draft assessment, summarized in Attachment 2, specifically considers your observations with respect to nine special-status fish species noted as potentially occurring in the Ohio River at the BVPS site and at crossings of the Ohio River by transmission lines that connect to the Beaver Valley Substation [References (b) and (c) above]. Based on our assessment, FENOC believes that extended operation and maintenance of BVPS and the transmission corridors being considered in the LRA would have no significant impact on threatened, endangered, or candidate species under PFBC jurisdiction. FENOC has not identified any land disturbing activities that would be undertaken for license renewal, and notes further that none of the transmission lines being considered in the LRA involve crossing of the Ohio River. In addition, both FENOC and Duquesne Light would continue to be subject to applicable regulatory controls for the period of extended operation. Neither FENOC nor Duquesne Light is aware of any adverse impact to populations of any threatened, endangered, or candidate species from past or current operation of BVPS or these transmission lines.

FENOC respectfully requests that the PFBC (1) formally notify us of any additional concerns or relevant information regarding threatened, endangered, and candidate species pertinent to our preliminary draft assessment and (2), as appropriate, concur with the assessment. FENOC will evaluate any information you provide for inclusion in the assessment, and will include your response to this request in the final LRA environmental report submitted to the NRC. FENOC would appreciate receiving your response within 60 days of receipt to provide ample time to evaluate and incorporate your response into our LRA environmental report for submittal to the NRC.

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Page 3

Thank you for your assistance as we complete this important environmental assessment. Please address any comments or questions you may have to Mr. Mark Ackerman, License Renewal Project Manager, by telephone at (724) 682-7994, e-mail ackermanm@firstenergycorp.com, or at the letterhead address above.

Sincerely,

L. W. Pearce

L. William Pearce
Site Vice President

Attachments: Project Maps (Attachment 1)
Preliminary Assessment (Attachment 2)

L-03-085
Page 4

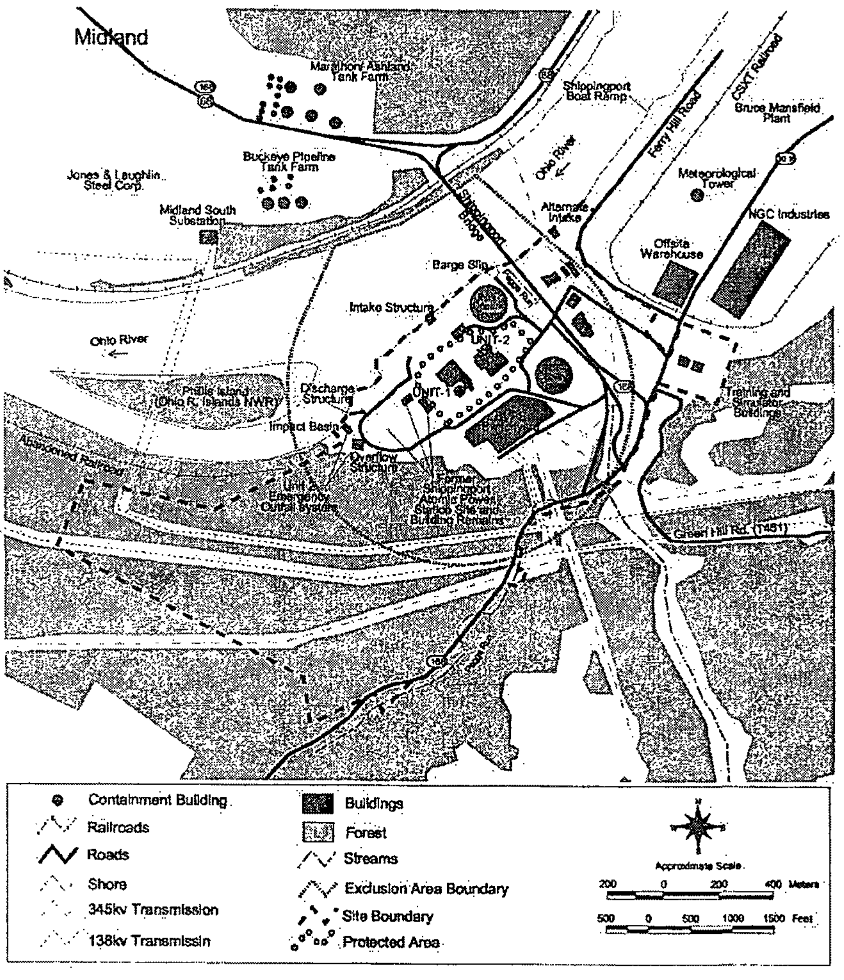
bc: G. DeCamp (CNS)
T. Grenci (CNS)
M. S. Ackerman (3 copies)
Central File

ATTACHMENT 1

PROJECT MAPS

FIGURE 1

BEAVER VALLEY POWER STATION SITE MAP

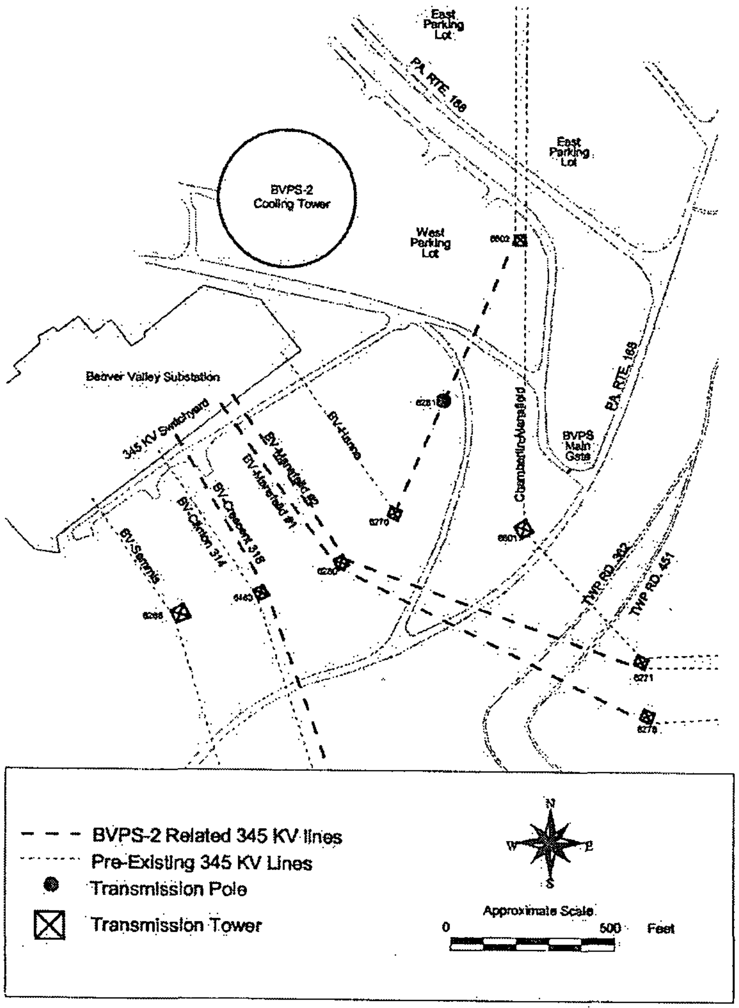


BVPS LRA Preliminary Assessment
Project Maps

Att. 1-1

FIGURE 2

345 kV RECONFIGURATIONS FOR BEAVER VALLEY POWER STATION UNIT 2

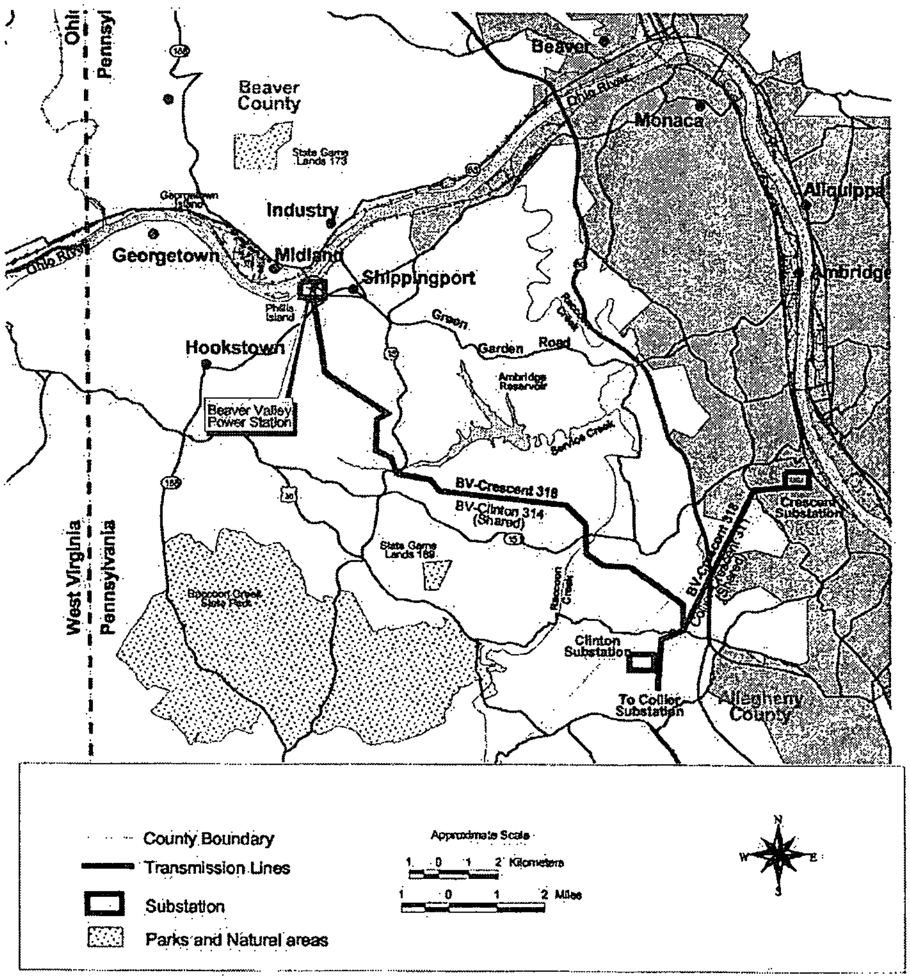


BVPS LRA Preliminary Assessment
Project Maps

Att. 1-2

FIGURE 3

BEAVER VALLEY-CRESCENT LINE 318 CORRIDOR



BVPS LRA Preliminary Assessment Att. 1-3
Project Maps

ATTACHMENT 2

PRELIMINARY ASSESSMENT

PENNSYLVANIA THREATENED, ENDANGERED, AND CANDIDATE SPECIES
SUBJECT TO PA FISH AND BOAT COMMISSION JURISDICTION
OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL

TABLE 1

PENNSYLVANIA THREATENED, ENDANGERED, AND CANDIDATE SPECIES SUBJECT TO PENNSYLVANIA FISH AND BOAT COMMISSION JURISDICTION OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL[a]

Common Name Scientific Name	U.S. Status[b]	PA Status[b]	Habitat/Occurrence[c]
			Aquatic Invertebrates
Northern riffleshell *Epioblasma torulosa rangiana*	E	E	Large and small streams, preferring runs with bottoms of firmly packed sand and fine to coarse gravel; recent occurrence in PA limited to upper Allegheny River watershed (Ref. 1; Ref. 2). No recent documented occurrences in Ohio River downstream as far as Meldahl Pool (Ref. 3). No PNDI record of observation in lower Allegheny River/Upper Ohio River in PA since 1919 or earlier (Ref. 4, Appendix J). Not reported by PNDI or PFBC as occurring in the Ohio River or other water bodies in the vicinity of the BVPS site or Beaver Valley-Crescent Line 318 (Ref. 5, Ref. 6, Ref. 7, Ref. 8).
Clubshell *Pleurobema clava*	E	E	Small rivers and streams in clean-sweep sand and gravel; has been found buried 2-4 inches in clean, loose sand. Recent occurrence in Ohio River drainage in PA limited to upper Allegheny River watershed. (Ref. 9). No recent documented occurrences in Ohio River downstream as far as Meldahl Pool (Ref. 3). No PNDI record of observation in lower Allegheny River/Upper Ohio River in PA since 1919 or earlier (Ref. 4, Appendix J). Not reported by PNDI or PFBC as occurring in the Ohio River or other water bodies in the vicinity of the BVPS site or Beaver Valley-Crescent Line 318 (Ref. 5, Ref. 6, Ref. 7, Ref. 8).

Common Name Scientific Name	U.S. Status[b]	PA Status[b]	Habitat/Occurrence[c]
			Fish
Silver chub *Macrhybopsis storeriana*	-	E	Inhabits the bottoms of large low- or base-gradient streams with clean gravel and sand substrate; potential threats likely include pollutants and siltation (Ref. 10, pages 277-278). Identified by PNDI and PFBC as potentially occurring in the Ohio River in the vicinity of the BVPS site (Ref. 5). Recent collections include: ORSANCO (1992-2001): Collected 4 of 7 years; total 250 individuals (0.8 percent of catch) BVPS (1992-2001): Collected 4 of 10 years; total 21 individuals (see Table 3). Initially reported in 1988. Two specimens (dead) noted in impingement samples in 1988. PFBC (1991): 22 individuals collected ODNR (1993): Not collected
Skipjack herring *Alosa chrysochloris*	-	T	Large river species, highly migratory, and historically known to congregate in swift waters below dams on the Ohio River. Potential threats likely include turbidity (Ref. 10, pages 195-197). Identified by PNDI and PFBC as potentially occurring in the Ohio River in the vicinity of the BVPS site (Ref. 5). Recent collections include: ORSANCO (1992-2001): Collected 5 of 7 years; total 776 individuals (2.4 percent of catch) BVPS (1992-2001): Collected 1 of 10 years; total 4 individuals (see Table 3). Initially reported in 1970-72. PFBC (1991): Not collected ODNR (1993): Not collected

Common Name Scientific Name	U.S. Status[b]	PA Status[b]	Habitat/Occurrence[c]
Goldeye *Hiodon alosoides*	-	T	Pelagic, large river species historically known to congregate in swift waters below dams on the Ohio River. Relatively tolerant of turbidity, but potentially intolerant of industrial pollutants (Ref. 10, pages 207-209; Ref. 11, pages 54-55). Identified by PNDI and PFBC as potentially occurring in the Ohio River in the vicinity of the BVPS site (Ref. 5). Recent collections include: ORSANCO (1992-2001): 0 individuals (0 percent of catch) BVPS (1992-2001): 0 individuals (see Table 3). Initially reported in 1970-72. PFBC (1991): 1 individual collected ODNR (1993): Not collected
Mooneye *Hiodon tergisus*	-	T	Prefers large, clear waters with abundant forage; although often found in non-flowing waters, feeds mostly in swift waters, such as occur below dams. Intolerant of silt and turbidity (Ref. 10, pages 10-212; Ref. 11, page 55). Identified by PNDI and PFBC as potentially occurring in the Ohio River in the vicinity of the BVPS site (Ref. 5). Recent collections include: ORSANCO (1992-2001): Collected 5 of 7 years; total 18 individuals. (0.1 percent of catch) BVPS (1992-2001): Collected 6 of 10 years; total 43 individuals (see Table 3). Initially reported in 1986. PFBC (1991): 16 individuals collected ODNR (1993): Not collected

Common Name Scientific Name	U.S. Status[b]	PA Status[b]	Habitat/Occurrence[c]
Smallmouth buffalo *Ictiobus bubalus*	-	T	Inhabits deep, clear waters of larger rivers with only moderate current (Ref. 11, pages 131-132). Identified by PNDI and PFBC as potentially occurring in the Ohio River in the vicinity of the BVPS site (Ref. 5). Recent collections include: ORSANCO (1992-2001): Collected 7 of 7 years; total 422 individuals. (1.3 percent of catch) BVPS (1992-2001): Collected 9 of 10 years; total 51 individuals (see Table 3). Initially reported in 1972-73. PFBC (1991): 6 individuals collected ODNR (1993): Collected
Channel darter *Percina copelandi*	-	T	Large clean streams and rivers with moderate current and substrate of large rocks, fine gravel, and sand; riffles are used for spawning and summer feeding, and deeper, quieter backwaters are used in winter. Now found primarily in upper Allegheny River system in PA (Ref. 12). Identified by PNDI and PFBC as potentially occurring in the Ohio River in the vicinity of the BVPS site (Ref. 5). Recent collections include: ORSANCO (1992-2001): Collected 2 of 7 years; total 2 individuals. (0.01 percent of catch) BVPS (1992-2001): 0 individuals (see Table 3). Initially reported in 1976. One specimen (live) noted in impingement samples in 1983 and reported occurrence in impingement samples prior to 1980. PFBC (1991): Not collected ODNR (1993): Not collected

Common Name Scientific Name	U.S. Status[b]	PA Status[b]	Habitat/Occurrence[c]
Brook silverside *Labidesthes sicculus*	-	C	More common in lakes than in streams. Prefers quiet waters with low turbidity; surface feeder. Spawns on gravel in moderate current. Potential threats likely include turbidity (Ref. 10, pages 533-535; Ref. 11, pages 160-161). Identified by PNDI and PFBC as potentially occurring in the Ohio River in the vicinity of the BVPS site (Ref. 5). Recent collections include: ORSANCO (1992-2001): Collected 1 of 7 years; total 1 individual. (<0.01 percent of catch) BVPS (1992-2001): Collected 2 of 10 years; total 2 individuals (see Table 3). Initially reported in 1983. PFBC (1991): Not collected ODNR (1993): Collected
Longnose gar *Lepisosteus osseus*	-	C	Inhabits the surface of low or base-gradient clear streams; potential threats likely include turbidity and siltation (Ref. 10, pages 186-188). Identified by PNDI and PFBC as potentially occurring in the Ohio River in the vicinity of the BVPS site (Ref. 5). Recent collections include: ORSANCO (1992-2001): Collected 3 of 7 years; total 16 individuals. (0.05 percent of catch) BVPS (1992-2001): Collected 7 of 10 years; total 32 individuals. Including individuals observed but not collected during electrofishing, 9 of 10 years, 40 individuals (see Table 3). Initially reported in 1976. PFBC (1991): 14 individuals collected ODNR (1993): Not collected

Common Name Scientific Name	U.S. Status[b]	PA Status[b]	Habitat/Occurrence[c]
River redhorse *Moxostoma carinatum*	-	C	Prefers deeper waters of Ohio River and lower portions of larger tributaries. Intolerant of turbidity and siltation (Ref. 10, pages 448-451). Identified by PNDI and PFBC as potentially occurring in the Ohio River in the vicinity of the BVPS site (Ref. 5). Recent collections include: ORSANCO (1992-2001): Collected 1 of 7 years; total 2 individuals. (0.01 percent of catch) BVPS (1992-2001): Collected 2 of 10 years; total 9 individuals (see Table 3). Initially reported in 1970-72. PFBC (1991): 1 individual collected ODNR (1993): Not collected
			Reptiles
Eastern massasauga *Sistrurus catenatus*	C	E	Relatively open old field and wet meadow habitat with low-lying areas of saturated soil and higher, drier ground nearby, which is found in PA only in relic prairie terrain in western counties. No historical occurrences in Beaver County; historical occurrence in northeastern Allegheny Co., but not since 1980 (Ref. 13). However, both Counties are south of its range as indicated by Conant (Ref. 14). This species was not collected or observed in the initial ecological survey conducted at the BVPS site (Ref. 15, Table 2.2-16) or site reconnaissance conducted in 2002 (Ref. 16), and little or no wetland habitat suitable for this species exists in the BVPS site vicinity or along the Beaver Valley-Crescent Line 318 corridor. This species was not identified by PNDI or PFBC as potentially occurring in the vicinity of the BVPS site or Beaver Valley-Crescent Line 318 transmission line corridor (Ref. 5; Ref. 6; Ref. 7, Ref. 8).

Common Name Scientific Name	U.S. Status[b]	PA Status[b]	Habitat/Occurrence[c]
Timber rattlesnake *Crotalus horridus*	-	C	Prefers woodland habitat variously characterized by remote, mountainous terrain with steep ledges and rock slides; timbered areas with rock outcroppings, dry ridges, and second growth forest. Overwinters in communal underground dens in rocky areas. Primary current threat is habitat destruction, but includes hunting and shooting of individuals (Ref. 17). This species was not collected or observed in the initial ecological survey conducted at the BVPS site (Ref. 15, Table 2.2-16) or site reconnaissance conducted in 2002 (Ref. 16), and was not identified by PNDI or PFBC as potentially occurring in the vicinity of the BVPS site or Beaver Valley-Crescent Line 318 transmission line corridor (Ref. 5, Ref. 6, Ref. 7, Ref. 8).

a. Tabulated species include: A) Federally designated threatened, endangered, and candidate species within PFBC jurisdiction reported by the U.S. Fish and Wildlife Service (FWS) for Pennsylvania (Ref. 18, Ref. 19) with known historical ranges that include the upper Ohio River or southwestern Pennsylvania, except those considered to be extirpated in PA, e.g., by the Pennsylvania Biological Survey (Ref. 20); and (B) the following species officially listed as endangered, threatened, or candidates for listing by the Commonwealth of Pennsylvania (Pennsylvania Code, Title 58, Chapter 75): (1) species within the jurisdiction of PFBC noted by PNDI or PFBC as potentially occurring in the vicinity of BVPS, including the Ohio River and Phillis Island, or the vicinity of the Beaver Valley-Crescent Line 318 transmission corridor (Ref. 5, Ref. 6, Ref. 7, Ref. 8); and (2) amphibian and reptile species with ranges that include Beaver County or Allegheny County based on Conant (Ref. 14).
b. Status Codes: E = Endangered, T = Threatened, C = Candidate for Listing, U = Undetermined Status
c. Fish survey data from the following sources: ORSANCO Montgomery and New Cumberland Locks rotenone sampling and New Cumberland Pool electrofishing, 1992-2001 (Ref. 21); BVPS monitoring as reported in BVPS Annual Environmental Reports Nonradiological for 1980-2001 (Ref. 22) and BVPS-2 Environmental Report – Operating License Stage (Ref. 15); Pennsylvania Fish and Boat Commission (PFBC) gill netting, electrofishing, and seining in New Cumberland Pool, 1991 (Ref. 23), and Ohio Department of Natural Resources electrofishing in the New Cumberland Pool, 1993 (Ref. 24).

FENOC = FirstEnergy Nuclear Operating Company
FWS = U.S. Fish and Wildlife Service
BVPS = Beaver Valley Power Station
ORSANCO = Ohio River Basin Sanitation Commission
ODNR = Ohio Department of Natural Resources
PA = Pennsylvania
PFBC = Pennsylvania Fish and Boat Commission
PNDI = Pennsylvania Natural Diversity Inventory

TABLE 2

SUMMARY IMPACT ASSESSMENT FOR THREATENED, ENDANGERED, AND CANDIDATE SPECIES SUBJECT TO PENNSYLVANIA FISH AND BOAT COMMISSION JURISDICTION OF POTENTIAL CONCERN TO BVPS LICENSE RENEWAL[a]

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
		Invertebrates	
Northern riffleshell *Epioblasma torulosa rangiana* FE, PE Clubshell *Pleurobema clava* FE, PE	(Applicable to all) None to Low. Last documented occurrence in the upper Ohio River or lower Allegheny River in early 1900s. However, recent surveys have documented the presence in the New Cumberland Pool, including the Phillis Island backchannel, of other unionid mussel species not recorded there since the early 1900s, and indicate that some mussels listed by PA or FWS may recolonize upper Ohio River pools in the future (Ref. 3).	(Applicable to all) Maintenance dredging (e.g., barge slip) Cooling water and wastewater discharges. Unplanned petroleum or hazardous materials spills/releases.	(Applicable to all) • Maintenance dredging is regulated by USACE and PADEP permits. • Cooling water and wastewater discharges are regulated by NPDES permit, which includes discharge limits and monitoring requirements. • Controls are established for prevention, preparedness, and response to unplanned spills and releases (e.g., *BVPS Preparedness, Prevention, and Contingency Plan*) • Closed-cycle cooling, tendency of plume to remain at surface, and low probability of simultaneous shutdown of both BVPS units reduces potential for adverse thermal impacts. • Unionid mussel population increase or recolonization at Phillis Island, downstream from BVPS outfall, apparently has occurred since BVPS initiated operation. • Benthic macroinvertebrate monitoring at BVPS, conducted annually from 1973 through present, indicates that BVPS is not adversely affecting the benthic macroinvertebrate community. The NRC concurred and deleted the requirement for benthic macroinvertebrate monitoring in 1980 with Amendment 25 to the BVPS-1 Technical Specifications. • FENOC has not identified any significant land disturbing activities that would be undertaken for license renewal either

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
			on or in the vicinity of the BVPS site or along the Beaver Valley-Crescent Line 318 corridor. • Results of PNDI searches, conducted at FENOC's request, (Ref. 5, Ref. 6, Ref. 7, Ref. 8) have not identified these or other listed or candidate invertebrate species within PFBC jurisdiction as potential conflicts with BVPS or transmission line operation. Impact Conclusion: SMALL
Fish			
Silver chub *Macrhybopsis storeriana* PE Skipjack herring *Alosa chrysochloris* PT Goldeye *Hiodon alosoides* PT Mooneye *Hiodon tergisus* PT Smallmouth buffalo *Ictiobus bubalus* PT Channel darter *Percina copelandi* PT	(Applicable to all in fish section) High. Presence of all of these species in the New Cumberland Pool has been recently documented, and silver chub, skipjack herring, smallmouth buffalo, and longnose gar have been recently collected with relatively high frequency and/or in relatively high abundance. Pollution-intolerant species such as mooneye, goldeye, skipjack herring, and river redhorse have reportedly increased in the upper Ohio River consistent with improvements in water quality (Ref. 22).	(Applicable to all in fish section) Maintenance dredging (e.g., barge slip) Cooling water and wastewater discharges Unplanned petroleum or hazardous materials spills/releases. Entrainment of early life stages in cooling water Impingement of fish on intake screens	(Applicable to all in fish section) • Maintenance dredging is regulated by USACE and PADEP permits. • Cooling water and wastewater discharges are regulated by NPDES permit, which includes discharge limits and monitoring requirements. • Controls are established for prevention, preparedness, and response to unplanned spills and releases (e.g., *BVPS Preparedness, Prevention, and Contingency Plan*) • Closed-cycle cooling reduces potential for adverse impact from impingement, entrainment, and thermal impacts. • BVPS units are not normally shut down simultaneously, reducing potential for impact from cold shock. • Increase in populations of some of these species has occurred since BVPS initiated operation. • Annual monitoring of the fish community at BVPS indicates presence of special-status fish species at both control and non-control stations (see Table 3).

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
Brook silverside *Labidesthes sicculus* PC Longnose gar *Lepisosteus osseus* PC River redhorse *Moxostoma carinatum* PC			• Monitoring of fish egg and larvae entrainment, conducted at BVPS from 1976 through 1995, indicated that entrainment impacts were not significant. The NRC concurred and deleted these monitoring requirements in 1980 with Amendment 5 to the BVPS-1 Technical Specifications. [Entrainment monitoring was continued on voluntary basis until 1995.] • Monitoring of fish impingement at BVPS, conducted at BVPS from 1976 through 1995, indicated that impingement losses were small and had little or no impact on fish populations in the river. The NRC concurred and deleted this monitoring requirement in 1983 with Amendment 64 to the BVPS-1 Technical Specifications. [Monitoring continued until 1995 on a voluntary basis.] • Review of BVPS annual monitoring reports through 2001 indicates that none of these species were specifically identified in fish egg and larvae samples collected during entrainment monitoring, and that the only incidences of impingement of these species noted in impingement monitoring conducted from 1980 through 1995 were: 2 silver chubs found dead on the screens in 1988, 1 in an operating bay and 1 in a non-operating bay, and 1 live channel darter found on an intake screen in 1983. • Results of PNDI searches and associated species impact reviews by PFBC (Ref. 5, Ref. 6, Ref. 7, Ref. 8), conducted at FENOC's request, identified these species as potential conflicts with BVPS operation and crossings of the Ohio River by BVPS-associated transmission lines. However, transmission lines addressed in the BVPS license renewal environmental review cross only Ohio River tributary streams (by spanning). PFBC (Ref. 6, Ref. 8) indicated that these species are vulnerable to physical and chemical changes to their aquatic environment, and that if environmentally invasive activities will affect any waterways at the site, additional information would be required for a more thorough PFBC

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	Additional Impact Considerations and Conclusions[c]
			evaluation. PFBC further indicated that if there will be no disturbance or impacts to waterways, and provided that if best management practices are used and an approved strict erosion/sedimentation control plan is maintained, then no significant adverse impacts to rare or protected species under PFBC jurisdiction are anticipated. • FENOC has not identified any significant land disturbing activities that would be undertaken for license renewal either on or in the vicinity of the BVPS site or along the Beaver Valley-Crescent Line 318 corridor, and notes that effective controls, summarized above, are in place to minimize potential for operational impacts. Impact Conclusion: SMALL
Reptiles			
Eastern massasauga *Sistrurus catenatus* FC, PE	None to Low. No recent confirmed occurrence in Beaver or Allegheny Counties. Little or no suitable wetland habitat on or near BVPS site or Beaver Valley-Crescent Line 318 transmission corridor. *Not collected or observed* in 1974-75 ecological surveys of BVPS site (Ref. 15, Table 2.2-16) or 2002 site reconnaissance (Ref. 16)	No significant initiators.	• Results of PNDI searches and associated species impact reviews by PFBC (Ref. 5, Ref. 6, Ref. 7, Ref. 8), conducted at FENOC's request, have not identified these species as potential conflicts with BVPS or transmission line operation. • FENOC has not identified any significant land disturbing activities that would be undertaken for license renewal either on or in the vicinity of the BVPS site or along the Beaver Valley-Crescent Line 318 corridor, Impact Conclusion: SMALL

Species and Status[a,b]	Occurrence Potential[a]	Impact Initiators	*Additional Impact Considerations and Conclusions*[c]
Timber rattlesnake *Crotalus horridus* PC	Low on BVPS site. Low to moderate on or near Beaver Valley-Crescent Line 318 transmission corridor, based on potential habitat availability. Not collected or observed in 1974-75 ecological surveys of BVPS site (Ref. 15, Table 2.2-16) or site reconnaissance conducted in 2002 (Ref. 16)		

a. Tabulated species, status, and occurrence potential based on information presented in Table 1.
b. Status Codes: FE = Federal Endangered, FT = Federal Threatened, FC = Federal Candidate for Listing, PE = PA Endangered, PT = PA Threatened, PC = PA Candidate for Listing.
c. Additional considerations include controls established for impact initiators, industry and plant experience related to potential impacts, information received from regulatory agencies, and other relevant factors.

FWS = U.S. Fish and Wildlife Service
BVPS = Beaver Valley Power Station
NPDES = National Pollutant Discharge Elimination System
NRC = U.S. Nuclear Regulatory Commission
PA = Pennsylvania
PADEP = Pennsylvania Department of Environmental Protection
PDCNR = PA Department of Conservation and Natural Resources
PFBC = Pennsylvania Fish and Boat Commission
PNDI = Pennsylvania Natural Diversity Inventory
USACE = U.S. Army Corps of Engineers

TABLE 3

SUMMARY OF SPECIAL STATUS FISH COLLECTIONS AT BEAVER VALLEY POWER STATION, 1992-2001[a]

	Station 1 (Control)[c]			Station 2A (Noncontrol)[c]		Station 2B (Noncontrol)[c]			Station 3 (Noncontrol)[c]		Annual
Year[b]	Gill net	Electrofish	Seine	Gill net	Electrofish	Gill net	Electrofish	Seine	Gill net	Electrofish	Subtotal
					Macrhybopsis storeriana (Silver chub)						
1992	0	0	NA[d]	0	0	0	0	NA	0	0	0
1993	0	3	0	0	0	0	0	0	0	0	3
1994	0	2	2	0	2	0	0	1	0	3	10
1995	0	0	0	0	2	0	2	0	0	1	5
1996	NA	0	0	NA	0	NA	0	0	NA	0	0
1997	NA	0	0	NA	2	NA	0	0	NA	1	3
1998	NA	0	0	NA	0	NA	0	0	NA	0	0
1999	NA	0	0	NA	0	NA	0	0	NA	0	0
2000	NA	0	0	NA	0	NA	0	0	NA	0	0
2001	NA	0	0	NA	0	NA	0	0	NA	0	0
Total	**0**	**5**	**2**	**0**	**6**	**0**	**2**	**1**	**0**	**5**	**21**
					Alosa chrysochloris (Skipjack herring)						
1992	0	0	NA	0	0	0	0	NA	0	0	0
1993	0	0	0	0	0	0	0	0	0	0	0
1994	0	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0	0
1996	NA	0	0	NA	0	NA	0	0	NA	0	0
1997	NA	4	0	NA	0	NA	0	0	NA	0	4
1998	NA	0	0	NA	0	NA	0	0	NA	0	0
1999	NA	0	0	NA	0	NA	0	0	NA	0	0
2000	NA	0	0	NA	0	NA	0	0	NA	0	0
2001	NA	0	0	NA	0	NA	0	0	NA	0	0
Total	**0**	**4**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**4**
					Hiodon tergisus (Mooneye)						
1992	0	0	NA	0	0	0	0	NA	0	0	0
1993	3	6	0	0	1	0	2	0	1	10	23
1994	1	1	0	0	0	0	3	0	0	0	5

Year[b]	Station 1 (Control)[c]			Station 2A (Noncontrol)[c]		Station 2B (Noncontrol)[c]			Station 3 (Noncontrol)[c]		Annual Subtotal
	Gill net	Electrofish	Seine	Gill net	Electrofish	Gill net	Electrofish	Seine	Gill net	Electrofish	
1995	0	2	0	1	0	0	0	0	0	0	3
1996	NA	0	0	NA	0	NA	0	0	NA	0	0
1997	NA	4	0	NA	1	NA	3	0	NA	0	8
1998	NA	0	0	NA	0	NA	3	0	NA	0	3
1999	NA	0	0	NA	0	NA	1	0	NA	0	1
2000	NA	0	0	NA	0	NA	0	0	NA	0	0
2001	NA	0	0	NA	0	NA	0	0	NA	0	0
Total	**4**	**13**	**0**	**1**	**2**	**0**	**12**	**0**	**1**	**10**	**43**
Ictiobus bubalus (Smallmouth Buffalo)											
1992	0	0	NA	0	0	0	0	NA	0	0	0
1993	0	1	0	1	0	0	2	0	2	3	9
1994	0	0	0	1	0	0	1	0	2	0	4
1995	2	1	0	1	2	3	2	0	3	1	15
1996	NA	0	0	NA	1	NA	0	0	NA	0	1
1997	NA	2	0	NA	1	NA	2	0	NA	0	5
1998	NA	0	0	NA	0	NA	3	0	NA	0	3
1999	NA	0	0	NA	1	NA	0	0	NA	0	1
2000	NA	6	0	NA	2	NA	0	0	NA	1	9
2001	NA	4	0	NA	0	NA	0	0	NA	0	4
Total	**2**	**14**	**0**	**3**	**7**	**3**	**10**	**0**	**7**	**5**	**51**
Percina copelandi (Channel Darter)											
1992	0	0	NA	0	0	0	0	NA	0	0	0
1993	0	0	0	0	0	0	0	0	0	0	0
1994	0	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0	0
1996	NA	0	0	NA	0	NA	0	0	NA	0	0
1997	NA	0	0	NA	0	NA	0	0	NA	0	0
1998	NA	0	0	NA	0	NA	0	0	NA	0	0
1999	NA	0	0	NA	0	NA	0	0	NA	0	0
2000	NA	0	0	NA	0	NA	0	0	NA	0	0
2001	NA	0	0	NA	0	NA	0	0	NA	0	0
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Year[b]	Station 1 (Control)[c] Gill net	Station 1 (Control)[c] Electrofish	Station 1 (Control)[c] Seine	Station 2A (Noncontrol)[c] Gill net	Station 2A (Noncontrol)[c] Electrofish	Station 2B (Noncontrol)[c] Gill net	Station 2B (Noncontrol)[c] Electrofish	Station 2B (Noncontrol)[c] Seine	Station 3 (Noncontrol)[c] Gill net	Station 3 (Noncontrol)[c] Electrofish	Annual Subtotal
Labidesthes sicculus (Brook Silverside)											
1992	0	0	NA	0	0	0	0	NA	0	0	0
1993	0	1	0	0	0	0	0	0	0	0	1
1994	0	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0	0
1996	NA	0	0	NA	0	NA	0	0	NA	0	0
1997	NA	0	0	NA	0	NA	0	0	NA	0	0
1998	NA	0	0	NA	0	NA	0	1	NA	0	1
1999	NA	0	0	NA	0	NA	0	0	NA	0	0
2000	NA	0	0	NA	0	NA	0	0	NA	0	0
2001	NA	0	0	NA	0	NA	0	0	NA	0	0
Total	**0**	**1**	**0**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**2**
Lepisosteus osseus (Longnose Gar)[e]											
1992	0	1	NA	0	0	1	0	NA	1	0	3
1993	2	0	0	0	1	3	2	0	3	0	11
1994	0	0	0	1	0	1	0	0	0	0	2
1995	0	0	0	0	1	3	0	0	5	0	9
1996	NA	0	0	NA	0	NA	1	0	NA	0	1
1997	NA	1	0	NA	0	NA	0	0	NA	0	1
1998	NA	0	0	NA	0	NA	0	0	NA	0	0
1999	NA	0	0	NA	0	NA	0	0	NA	0	0
2000	NA	0	0	NA	2	NA	2	0	NA	1	5
2001	NA	0	0	NA	0	NA	0	0	NA	0	0
Total	**2**	**2**	**0**	**1**	**4**	**8**	**5**	**0**	**9**	**1**	**32**
Moxostoma carinatum (River Redhorse)											
1992	0	0	NA	0	0	0	0	NA	0	0	0
1993	0	0	0	0	2	0	0	0	0	0	2
1994	0	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0	0
1996	NA	0	0	NA	0	NA	0	0	NA	0	0
1997	NA	0	0	NA	0	NA	0	0	NA	0	0
1998	NA	0	0	NA	0	NA	0	0	NA	0	0
1999	NA	0	0	NA	0	NA	0	0	NA	0	0

	Station 1 (Control)[c]			Station 2A (Noncontrol)[c]		Station 2B (Noncontrol)[c]			Station 3 (Noncontrol)[c]		Annual
Year[b]	Gill net	Electrofish	Seine	Gill net	Electrofish	Gill net	Electrofish	Seine	Gill net	Electrofish	Subtotal
2000	NA	1	0	NA	3	NA	1	0	NA	2	7
2001	NA	0	0	NA	0	NA	0	0	NA	0	0
Total	**0**	**1**	**0**	**0**	**5**	**0**	**1**	**0**	**0**	**2**	**9**

a. Source: Beaver Valley Power Station Annual Environmental Monitoring Reports Nonradiological: 1992-2001 (collection) (Ref. 22), copies of which are routinely provided to the Pennsylvania Fish and Boat Commission.

b. In 2001, collections were performed during May and July only. For all other years, sampling was typically performed in May, July, September, and November.

c. Station 1 (control) is located upstream of BVPS on the Ohio River at approximate river mile (RM) 34.5. Stations 2A and 2B are located downstream from the BVPS discharges on the main channel and back channel at Phillis Island, respectively, at approximate RM 35. Station 3 is located downstream from BVPS at approximate RM 37. Seining consisted of three seine hauls at both Station 1 (north shore) and Station 2B (south shore) during each survey. Electrofishing was conducted on both the north and south shoreline areas at each station, for approximately 10 minutes of actual shocking time per survey (5 minutes along each shore at each station). Gill netting was conducted using one gill net set extending from the north shore and one gill net set extending from the south shore at each station for each sampling event. Nets were typically set in the afternoon/evening, left in place overnight, then pulled the following morning.

d. NA= No sampling conducted with indicated method.

e. From 1999 through 2001, total of 8 additional longnose gars were observed during electrofishing, as follows: 1 (1999), 6 (2000), 1 (2001). However, no note was made of the station where they were observed.

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Commonwealth of Pennsylvania
Pennsylvania Fish and Boat Commission
Division of Environmental Services
450 Robinson Lane
Bellefonte, PA 16823
814-359-5147
October 29, 2003

IN REPLY REFER TO
SIR# 9555, 11240

FENOC
Mark Ackerman
Beaver Valley Power Station
Route 168, PO Box 4
Shippingport, PA 15077-0004

RE: **Secondary Species Impact Review (SIR) - # 9555 and 11240**
Beaver Valley Power Station License Renewal
Beaver County, Pennsylvania

Dear Mr. Ackerman:

I have reviewed the information from the preliminary draft assessment of potential impacts of the Beaver Valley Power Station license renewal on rare, threatened, and endangered species falling under Pennsylvania Fish & Boat Commission (PFBC) jurisdiction.

In our previous correspondences for this project, we listed several species of fish in the Ohio River for which we had concerns about any proposed environmentally invasive activities. However, according to your letter and report, extended operation and maintenance of BVPS and associated transmission lines will not require any additional disturbance or impacts to waterways. Controls and procedures that are currently in place to protect fish from entrainment, impingement, and other adverse effects of the power station operation are expected to continue. Monitoring studies conducted at BVPS indicate that the plant operation has had some impact on fish populations in the river, the extent of which is unknown. For example, the state endangered silver chub (*Macrhybopsis storeriana*) and the state threatened channel darter (*Percina copelandi*) have been killed or captured via impingement in past monitoring surveys. These data do not account for incidents since 1995 or potential kills that occurred in between monitoring events. Safeguards need to be designed such that further "take" of endangered and threatened species is avoided. It was not clear in your submittal if measures have been taken to ameliorate this situation. Concurrence with the proposed project will not occur until we can be assured that steps have been taken to avoid further take of threatened and endangered fish species known from the project area. Please provide additional information regarding avoidance measures taken for impingement and entrainment of fish species in order for us to continue our review of this project.

Please contact Kathy Derge of my staff at (814) 359-5186 if you have any additional concerns regarding this response. Thank you for your cooperation and attention to this matter of threatened and endangered species conservation.

Sincerely,

Christopher A. Urban

Christopher A. Urban, Chief
Natural Diversity Section

KLD/
Cc: DEP-SW Region

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
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L. William Pearce
Site Vice President

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February 3, 2004
L-04-004

Mr. Christopher A. Urban
Chief, Natural Diversity Section
Pennsylvania Fish and Boat Commission
450 Robinson Lane
Bellefonte, PA 16823

Subject: Beaver Valley Power Station License Renewal Project
Fish Impingement and Entrainment Avoidance Measures

References: Letter L-03-085, L. William Pearce, BVPS Site Vice President, FENOC, to John A. Arway, Chief, Division of Environmental Services, Pennsylvania Fish and Boat Commission, September 8, 2003.

Letter SIR #9555, 11240, Christopher A. Urban, Chief, Natural Diversity Section, Pennsylvania Fish and Boat Commission, to Mark Ackerman, FENOC-BVPS, October 29, 2003.

Dear Mr. Urban:

Thank your for your response dated October 29, 2003 to our preliminary draft assessment of potential impacts of Beaver Valley Power Station (BVPS) license renewal on threatened, endangered, and candidate species under jurisdiction of the Pennsylvania Fish and Boat Commission (PFBC). In your letter, you requested additional information regarding avoidance measures taken for impingement and entrainment of fish species in order for your review of our license renewal project to continue.

First Energy Nuclear Operating Company (FENOC) is pleased to provide PFBC with additional information regarding fish impingement and entrainment at BVPS, including plant design and operating safeguards implemented to minimize these impacts. As indicated in our preliminary draft assessment provided to Mr. Arway in September, closed-cycle cooling is employed for BVPS Units 1 and 2. This technology reduces the potential for impingement and entrainment losses. Although the operating license renewal process will not change that selection in any way, we are providing the following synopsis of BVPS cooling system safeguards for your consideration.

Fish Impingement and Entrainment Avoidance Measures
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Page 2

Closed-cycle Cooling as 'Best Technology Available' – The U.S. Environmental Protection Agency (EPA), in its proposed rules for existing sources (67 *Federal Register* 17122, 4/9/02), considers closed-cycle cooling (employed at BVPS) 'Best Technology Available' for cooling water intake structures.

Reduced Ohio River Water Withdrawal Need – Closed-cycle cooling for BVPS reduces water withdrawals from the Ohio River to the maximum practical extent and well below that of a comparable once-through cooling system. At present, and for the period of extended operation afforded by license renewal, plant water withdrawals are approximately 145 cubic feet per second (cfs). This withdrawal occurs during periods of high river water temperatures (generally July – October) and is marginally reduced during the remainder of the year when river water temperatures moderate. The Ohio River at BVPS has an annual average flow of 39,503 cfs; long-term monthly average flow is lowest in August (16,526 cfs). Therefore, BVPS water withdrawal is approximately 0.4 percent and 0.9 percent of the annual and minimum monthly (August) average Ohio River flows at the BVPS, respectively.

By comparison, a once-through cooling system such as that originally contemplated for BVPS Unit 1 would withdraw a maximum of approximately 2,280 cfs, or approximately 6 percent and 14 percent, respectively, of the annual and minimum monthly average river flows. It is apparent from the flow comparisons that the closed-cycle cooling system technology used at the BVPS site now and during the license renewal period offers a significant reduction in river water withdrawal.

Beneficial Intake Structure Design – The low river water withdrawal need described above greatly reduces the potential to entrain passive and nearly passive early life stages of fish that drift past the BVPS. It also provides for beneficial design features for the cooling water intake structure, particularly greatly reduced effective screen area and entrance flow velocity. As a direct result of these important structure design safeguards, fish impingement potential is also greatly reduced.

Each of the intake structure's four, 0.375-inch mesh vertical screens (50 percent open area) is 14 feet wide. Each screen extends from the floor of the structure at elevation 646.0 feet National Geodetic Vertical Datum (NGVD) to above the standard project flood elevation of 705 feet NGVD. At normal elevation of the New Cumberland Pool (664.5 feet NGVD), which is maintained by the U.S. Army Corps of Engineers even under low flow conditions, the approach velocity and through-screen velocity of incoming water averages less than 0.3 feet per second (fps) and 0.5 fps, respectively. These intake velocities are lower than the swim speed capabilities of very small healthy fish, and are at or below the 0.5 fps guideline available at the time BVPS Unit 2 was initially constructed. EPA continues to cite the 0.5 fps guideline velocity in recent rulemakings to implement Section 316(b) of the Clean Water Act.

Fish Impingement and Entrainment Avoidance Measures
L-04-004
Page 3

Benign Intake Structure Siting – The intake structure is situated flush with the main channel shoreline at river mile 34.8, eliminating creation of an artificial embayment that would attract fish. This location is remote from tributaries, embayments, shallows, backwaters, and other habitats (e.g., dam tailwaters) that are particularly attractive to, or provide spawning or nursery habitat for, many important fish species in the New Cumberland Pool.

Optimized Intake Structure Operation – To maximize effective screen area and maintain low water intake velocities, the four vertical traveling screens at the BVPS intake structure are kept free of debris. A screen cleaning system automatically rotates and washes debris from the screens whenever the screen differential pressure reaches 6 inches of water. In addition, each screen bay is routinely inspected and cleaned quarterly or more frequently during periods of high river flow conditions when potential for silt and debris accumulation is greater than normal.

Aquatic Monitoring – The effectiveness of the BVPS cooling system in safeguarding endangered and threatened fish species of interest to our license renewal impacts assessment have been clearly demonstrated by scientific field studies. From 1976 to 1995, Duquesne Light Company (DLC, the former owner of BVPS) routinely examined and reported on the nature and extent of fish impingement and entrainment at the BVPS. Further, DLC and subsequently FENOC have monitored the Ohio River fish population diversity in the BVPS vicinity from 1976 through present. Because of their continuing corporate importance, this monitoring continues to be carried out on a voluntary basis. The aquatic monitoring program results have been documented in formal reports (see *Annual Environmental Report – Nonradiological, Beaver Valley Power Station, Units No. 1 & 2* series reports) routinely provided to the PFBC. Investigators conducting these studies have consistently concluded that these results indicate that BVPS operations have little or no effect on fish populations.

As we indicated in our preliminary assessment, none of the nine state-listed fish species addressed was specifically identified in BVPS entrainment samples. Appearance of these species in impingement samples in the most recent 10-years of impingement sampling (1986-1995), when both BVPS units were operating (BVPS Unit 2 began operation in 1987), was extremely rare. We note that the mere presence of fish in impingement collections at BVPS is not conclusive evidence that associated mortality of all such individuals is the result of BVPS operation. On the contrary, fish that have died or been weakened by factors other than plant operation are particularly susceptible to impingement.

In conclusion, FENOC intends to continue to ensure that the BVPS cooling water intake system is operated in a manner that is protective of Ohio River fish populations, including listed species, in the period of extended operation afforded by license renewal.

Fish Impingement and Entrainment Avoidance Measures
L-04-004
Page 4

We also intend to continue monitoring fish populations in the vicinity of BVPS and reporting results to PFBC on a voluntary basis as part of our environmental stewardship efforts. Finally, FENOC will continue to ensure that the BVPS cooling water intake system complies with requirements of the Clean Water Act, Section 316(b), including associated regulations for existing facilities that EPA expects to finalize in 2004. FENOC expects specific provisions of these new regulations will be applied to BVPS when the current National Pollutant Discharge Elimination System permit for the plant is renewed in 2006, within the terms of the current BVPS operating licenses.

We hope you find this additional information useful to your review of our preliminary assessment and that it provides the necessary assurance that the PFBC seeks.

No new commitments are contained in this submittal. Please address any comments or questions you may have to Mr. Mark Ackerman, License Renewal Project Manager, by telephone at (724) 682-7994, e-mail ackermanm@firstenergycorp.com, or at the letterhead address above.

Sincerely,

L. W. Pearce

L. William Pearce

cc: John A. Arway, PFBC

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

L. William Pearce
Site Vice President

724-682-5234
Fax: 724-643-8069

September 8, 2003
L-03-082

Mr. Charles Duritsa
Director, Southwest Region
Pennsylvania Department of Environmental Protection
400 Waterfront Drive
Pittsburgh, PA 15222

Subject: Beaver Valley Power Station License Renewal Project
Request for Information and Concurrence – Thermophilic Pathogens

Reference: Letter CNS-02-050, Julea B. Hovey, Constellation Nuclear Services, to David E. Hess, Pennsylvania Department of Environmental Protection, June 28, 2002

Dear Mr. Duritsa:

FirstEnergy Nuclear Operating Company (FENOC) is preparing an environmental report as part of our operating license renewal application (LRA) to the U.S. Nuclear Regulatory Commission (NRC) for the Beaver Valley Power Station (BVPS) Units 1 and 2. BVPS Units 1 and 2 have been in operation since 1976 and 1987, respectively. Successful renewal would provide the opportunity to operate the units for up to 20 years beyond the expiration of their current licenses in 2016 and 2027, respectively.

At a related meeting held August 12, 2002 at your offices in response to correspondence from our LRA consultant to the Pennsylvania Department of Environmental Protection (PADEP) referenced above, FENOC indicated that the LRA environmental review would include an assessment of public health impact from thermophilic microorganisms. Since that time, FENOC has completed a preliminary draft of that assessment, which will be finalized and included in the LRA environmental report. Accordingly, FENOC is now requesting PADEP assistance in finalizing our assessment to provide additional assurance that it is accurate and complete. By contacting you at this time, FENOC believes that the effectiveness of forthcoming NRC interactions with your office, described in the following paragraph, will be enhanced.

The NRC, at 10 CFR 51.53(c)(3)(ii)(G), requires that license renewal applicants include in the environmental report ". . . an assessment of the impact of the proposed action {license renewal} on public health from thermophilic organisms in the affected water" for plants that discharge cooling water into a river having an average annual flow rate of less than 3.15×10^{12} cubic feet per year, a condition applicable to BVPS, which discharges to the Ohio River near Shippingport, Pennsylvania (Attachment 1). This requirement stems from the NRC's conclusion that thermophilic organisms in the receiving water body are not expected to be a public health problem at most operating plants, but a generic determination for all plants is not possible in view of the need for site-specific information (10 CFR 51, Subpart A, Appendix B). The NRC staff routinely interacts with other affected agencies in conducting their environmental review,

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Page 2

which leads to preparation of a supplemental environmental impact statement (SEIS) for this licensing action. It is expected that the PADEP will be contacted regarding the potential impact of BVPS license renewal on public health from thermophilic organisms in the Ohio River as part of this activity. The following paragraphs describe relevant aspects of the NRC's generic assessment of this issue and FENOC's preliminary draft site-specific assessment for BVPS.

The NRC generic assessment of this issue is provided in Section 4.3.6 of its *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (see excerpt provided in Attachment 2). The NRC's concern relates to the potential for enhancement of thermophilic pathogens in the receiving water body from plant thermal discharges and consequent potential for adverse public health impacts. Organisms of concern include enteric pathogens (e.g., *Salmonella sp.*, *Shigella sp.*), *Pseudomonas aeruginosa*, thermophilic fungi, *Legionella sp.*, and, in particular, *Naegleria fowlerii*, a pathogenic free-living amoeba indigenous to soils. In its guidance, the NRC indicates that applicants should consult with the state agency responsible for environmental health to determine if there is a concern about the presence of *N. fowlerii* in plant receiving waters and obtain concurrence on its assessment and mitigation strategy, if one is required.

Based on our preliminary assessment of this issue, FENOC does not believe that operation of the BVPS units during the license renewal period would result in any significant threat to public health from thermophilic pathogens. A major factor in this determination is the observation that temperatures to which these organisms would be exposed are lower than are considered optimal for their proliferation (e.g., human body temperature of approximately 99°F; *N. fowlerii* is rarely found in water bodies cooler than 95°F) and the area affected by BVPS thermal discharges would be very small. BVPS uses cooling towers for both units. Discharge to the river consists of cooling tower blowdown and a limited quantity of once-through service water used to cool components. Based on past modeling studies, FENOC estimates that the resulting thermal plume, defined by the 5°F isotherm (i.e., maximum monthly average and daily temperatures of approximately 85°F and 91°F, respectively), would encompass less than 2 acres and extend downriver no more than a few hundred feet; little or no plume area would be warmer than 95°F for more than a brief time. Organisms that may inhabit sediments on the river bottom or immersed banks (e.g., *N. fowlerii*) would be exposed to increased temperatures in only a small area in the vicinity of the outfalls because the thermal plume is small and tends to remain near the surface.

FENOC also notes that there is little potential for significant introduction of thermophilic pathogens to the river from the BVPS cooling water discharge itself. Both the cooling tower blowdown and once-through cooling water are routinely treated with biocide for biofouling control, and some residual chlorine, within limits prescribed in the NPDES permit (No. PA0025615), may be discharged. These biocide applications significantly reduce the likelihood that microbial inoculants would be introduced in the discharge.

In addition, there is limited potential for significant human exposure to the thermally affected area. Shore-based recreation (e.g. fishing) on the BVPS property by the public is not permitted, and the U.S. Coast Guard has established a security zone, effective indefinitely, that encompasses all waters extending 200 feet from the shoreline at the BVPS site, including areas at and downstream from the discharge areas. Finally, FENOC is not aware of any public health concerns or incidences related to thermophilic organisms in the Ohio River attributable to current or past BVPS operation.

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Page 3

FENOC respectfully requests that the PADEP (1) formally notify us of any concerns or relevant information pertinent to our assessment and (2), as appropriate, concur with the assessment. It is FENOC's understanding that PADEP will coordinate this matter, as appropriate, with the Pennsylvania Department of Health. FENOC will evaluate any information you provide for inclusion in the assessment, and will include your response to this request in the final LRA environmental report submitted to the NRC. FENOC would appreciate receiving your response within 60 days of receipt to provide ample time to evaluate and incorporate your response into our LRA environmental report for submittal to the NRC.

Thank you for your assistance as we complete this important environmental assessment. Please address any comments or questions you may have to Mr. Mark Ackerman, License Renewal Project Manager, by telephone at (724) 682-7994, e-mail ackermanm@firstenergycorp.com, or at the letterhead address above.

Sincerely,

L.W. Pearce

L.William Pearce
Site Vice President

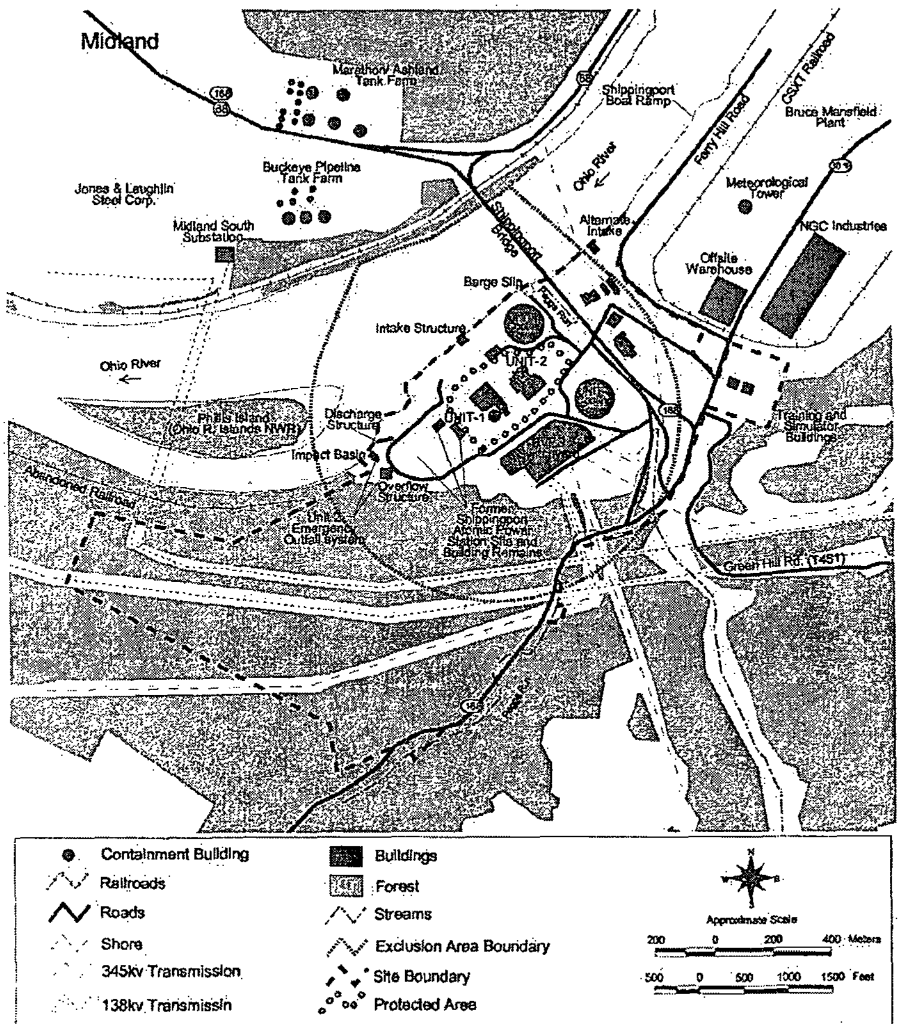
Attachments: Project Map (Attachment 1)
GEIS Section 4.3.6 (Attachment 2)

L-03-082
Page 4

bc: G. DeCamp (CNS)
T. Grenci (CNS)
M. S. Ackerman (3 copies)
Central File

ATTACHMENT 1

BEAVER VALLEY POWER STATION SITE MAP



BVPS LRA Environmental Review
Project Map

Att. 1-1

ATTACHMENT 2

GENERIC ENVIRONMENTAL IMPACT STATEMENT FOR LICENSE RENEWAL OF NUCLEAR PLANTS (NUREG-1437 VOL. 1)

4.3.6 Human Health

Some microorganisms associated with cooling towers and thermal discharges can have deleterious impacts on human health. Their presence can be enhanced by thermal additions. These microorganisms include the enteric pathogens *Salmonella sp.* and *Shigella sp.* as well as *Pseudomonas aeruginosa* and the thermophilic fungi (Appendix D). Tests for these pathogens are well established, and factors germane to their presence in aquatic environs are known and in some cases controllable. Other aquatic microorganisms normally present in surface waters have only recently been recognized as pathogenic for humans. Among these are Legionnaires' disease bacteria *Legionella sp.* and free-living amoebae of the genera *Naegleria* and *Acanthamoeba*, the causative agents of various, although rare, human infections. Factors affecting the distribution of *Legionella sp* and pathogenic free-living amoebae are not well understood. Simple, rapid tests for their detection and procedures for their control are not yet available. The impacts of nuclear plant cooling towers and thermal discharges are considered of small significance if they do not enhance the presence of microorganisms that are detrimental to water and public health.

Potential adverse health effects on workers due to enhancement of microorganisms are an issue for steam-electric plants that use cooling towers. Potential adverse health effects on the public from thermally enhanced microorganisms is an issue for the nuclear plants that use cooling ponds, lakes, or canals and that discharge to small rivers. These plants are all combined in the category of small river (average flow less than 2830 m^3/s (100,000 ft^3/s) in Tables 5.18 and 5.19 (Note: Table 5.18 lists the Beaver Valley Power Station). These issues were evaluated by reviewing what is known about the organisms that are potentially enhanced by operation of the steam-electric plants.

Because of the reported cases of fatal *Naegleria* infections associated with cooling towers, the distribution of these two pathogens in the power plant environs was studied in some detail (Tyndall et al. 1983; see also Appendix D). In response to these various studies (Appendix D), many electric utilities require respiratory protection for workers when cleaning cooling towers and condensers. However, no Occupational Safety and Health Administration (OSHA) or other legal standards for exposure to microorganisms exist at present. Also, for worker protection, one plant with high concentrations of *Naegleria fowlerii* in the circulating water successfully controlled the pathogen through chlorination before its yearly downtime operation (Tyndall et al. 1983).

Changes in the microbial population and in the use of bodies of water may occur after the operating license is issued and the application for license renewal is filed. Ancillary factors may also change, including average temperature of water resulting from climatic conditions. Finally, the long-term presence of a power plant may change the natural dynamics of harmful microorganisms within a body of water by raising the

NRC License Renewal GEIS
Section 4.3.6

Att. 2-1

4.3.6 Human Health, continued:

level of *N. fowlerii*, which are indigenous to the soils. Increased populations of *N. fowlerii* may have significant adverse impacts. On entry into the nasal passage of a susceptible individual, *N. fowlerii* will penetrate the nasal mucosa. The ensuing infection results in a rapidly fatal form of encephalitis. Fortunately, humans in general are resistant to infection with *N. fowlerii*. Hallenbeck and Brenniman (1989) have estimated individual annual risks for primary amebic meningoencephalitis caused by the free living *N. fowlerii* to swimmers in fresh water, to be approximately 4×10^{-6}. Heavily used lakes and other fresh bodies of water may merit special attention and possibly routine monitoring for *N. fowlerii*.

Thermophilic organisms may or may not be influenced by the operation of nuclear power plants. The issue is largely unstudied. However, NRC recognizes a potential health problem stemming from heated effluents. Occupational health questions are currently resolved using proven industrial hygiene principles to minimize worker exposures to these organisms in mists of cooling towers. NRC anticipates that all plants will continue to employ proven industrial hygiene principles so that adverse occupational health effects associated with microorganisms will be of small significance at all sites, and no mitigation measures beyond those implemented during the current term license would be warranted. Aside from continued application of accepted industrial hygiene procedures, no additional mitigation measures are expected to be warranted as a result of license renewal. This is a Category 1 issue.

Public health questions require additional consideration for the 25 plants using cooling ponds, lakes, canals, or small rivers (all under the small river category in Tables 5.18 and 5.19) because the operation of these plants may significantly enhance the presence of thermophilic organisms. The data for these sites are not now at hand and it is impossible to predict the level of thermophilic organism enhancement at any given site with current knowledge. Thus the impacts are not known and are site-specific. Therefore, the magnitude of the potential public health impacts associated with thermal enhancement of *N. fowlerii* cannot be determined generically. This is a Category 2 issue.

Pennsylvania Department of Environmental Protection

400 Waterfront Drive
Pittsburgh, PA 15222-4745

October 16, 2003

Southwest Regional Office

412-442-4000
Fax 412-442-4194

L. William Pearce, Site Vice-President
First Energy Nuclear Operating Company
Beaver Valley Power Station
Route 168, PO Box 4
Shippingport, PA 15077-0004

Re: Industrial Waste
NPDES Permit PA0025615
First Energy Nuclear Operating Company
Beaver Valley Power Station
License Renewal Project
Shippingport Borough
Beaver County

Dear Mr. Pearce:

Thank you for submitting the September 8, 2003 preliminary Draft Assessment of the Public Health Impacts from Thermophilic Microorganisms ("Draft Assessment"). This Draft Assessment is being prepared as part of the environmental report that is required to be submitted with the operating license renewal application for the Beaver Valley Power Station. We have forwarded this Draft Assessment to the Division of Water Quality Assessment and Standards in our Central Office and the Pennsylvania Department of Health for their review and comment. We have asked both entities to comment within 30 days. Once we receive input from the Division of Water Quality Assessment and Standards and the Department of Health, we will provide you with all comments by your requested deadline.

If you should have any questions concerning this matter please feel free to contact Kareen Milcic of my staff at 412-442-4033.

Sincerely,

Charles A. Duritsa
Regional Director
Southwest Regional Office

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

L. William Pearce
Site Vice President

724-682-5234
Fax: 724-643-8069

September 8, 2003
L-03-086

Ms. Jean Cutler
State Historic Preservation Officer
Pennsylvania Historical and Museum Commission
Bureau for Historic Preservation
Commonwealth Keystone Building, Second Floor
400 North Street
Harrisburg, PA 17120-0093

Subject: Beaver Valley Power Station License Renewal Project
Request for Information and Concurrence – Cultural Resources

References:
(a) Letter CNS-02-050, Julea B. Hovey, Constellation Nuclear Services, to Ms. Jean Cutler, Pennsylvania Historical and Museum Commission, June 28, 2002
(b) U.S. Atomic Energy Commission. *Final Environmental Statement related to the Beaver Valley Power Station, Unit 1; Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company.* Docket No. 50-334. Directorate of Licensing. Washington, D.C., July 1973.
(c) U.S. Atomic Energy Commission. *Final Environmental Statement related to the Beaver Valley Power Station, Unit 2; Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, Toledo Edison Company.* Docket No. 50-412. Directorate of Licensing. Washington, D.C., July 1973.
(d) U.S. Nuclear Regulatory Commission. *Final Environmental Statement related to the operation of Beaver Valley Power Station, Unit 2; Duquesne Light Company, et al.* Docket No. 50-412. Office of Nuclear Reactor Regulation. Washington, D.C., September 1985.

Dear Ms. Cutler:

FirstEnergy Nuclear Operating Company (FENOC) is preparing an environmental report as part of our operating license renewal application (LRA) to the U.S. Nuclear Regulatory Commission (NRC) for the Beaver Valley Power Station (BVPS) Units 1 and 2. BVPS Units 1 and 2 have been in operation since 1976 and 1987, respectively. Successful renewal would provide the opportunity to operate the units for up to 20 years beyond the expiration of their current licenses in 2016 and 2027, respectively.

In correspondence to the Pennsylvania Historical and Museum Commission [reference (a)], FENOC's LRA consultant indicated that the LRA environmental review would include an assessment of potential impacts of BVPS license renewal on cultural resources. Since that time, FENOC has completed a preliminary draft of our assessment, which will be finalized and included in the LRA environmental report. Accordingly, FENOC is now requesting Pennsylvania Historical and Museum Commission assistance in finalizing our assessment to provide additional assurance that it is accurate and complete. By contacting you at this time, FENOC believes that the effectiveness of forthcoming NRC interactions with your office, described in the following paragraph, will be enhanced.

L-03-086
Page 2

The NRC, at 10 CFR 51.53(c)(3)(ii)(K), requires that license renewal applicants include in their environmental report an assessment of ". . . whether any historic or archeological properties will be affected by the proposed project {license renewal}." The NRC staff routinely interacts with other affected agencies in conducting their environmental review, which leads to preparation of a supplemental environmental impact statement (SEIS) for this licensing action. It is expected that the Pennsylvania Historical and Museum Commission will be contacted regarding potential impact on historic and archeological resources as part of this activity. The following paragraphs describe relevant aspects of the BVPS environmental setting considered in the LRA and a synopsis of FENOC's assessment of potential impacts of BVPS license renewal on historic and archeological resources.

The BVPS site consists of approximately 450 acres on the south side of the Ohio River (New Cumberland Pool) at Shippingport, Beaver County, Pennsylvania (see Attachment 1, Figure 1). The intensively developed or maintained portion of the site, approximately 220 acres, is located on a gravel terrace adjacent to the river; the remainder of the site consists mostly of forested slopes.

Short segments of three transmission lines on and adjacent to the BVPS site and one transmission line extending 15.8 miles southeast from BVPS (Duquesne Light Company's Beaver Valley-Crescent Line 318) are also being addressed in the BVPS LRA environmental report (see Attachment 1, Figures 2 and 3). The latter transmission line corridor traverses primarily through forest and farmland. The transmission line segments being considered in the LRA environmental report have been in service since the mid-1980s.

Based on our preliminary draft assessment, FENOC believes that extended operation and maintenance of BVPS and the transmission corridors considered in the LRA would have no significant impact on historic or archeological resources. BVPS Unit 1 and Unit 2 were subject to environmental reviews by the Atomic Energy Commission and the NRC as part of their initial licensing activities, results of which were documented in Final Environmental Statements in 1973 [Ref. (b) and (c)] and 1985 [Ref. (d)]. Regulators concluded at that time that operation of the units would not be expected to have significant adverse impacts on historic or archeological resources. One historic site listed as eligible with the National Register of Historic Places, the Shippingport Atomic Power Station site, is located on the BVPS site. However, this facility has been largely dismantled and would not be affected by renewal of the BVPS operating licenses. FENOC's current review indicates that there are no other historical sites on the National Register of Historic Places located on or adjacent to either the BVPS site or the Beaver Valley-Crescent Line 318 transmission corridor. In addition, FENOC has not identified any significant land disturbing activities that would be undertaken for license renewal or continued operation of the plant or transmission line.

FENOC respectfully requests that the Pennsylvania Historical and Museum Commission (1) formally notify us of any additional concerns or relevant information regarding historic and archeological resources pertinent to our preliminary draft assessment and (2), as appropriate, concur with the assessment. FENOC will evaluate any information you provide for inclusion in the assessment, and will include your response to this request in the final LRA environmental report submitted to the NRC. FENOC would appreciate receiving your response within 60 days of receipt to provide ample time to evaluate and incorporate your response into our LRA environmental report for submittal to the NRC.

L-03-086
Page 3

Thank you for your assistance as we complete this important environmental assessment. Please address any comments or questions you may have to Mr. Mark Ackerman, License Renewal Project Manager, by telephone at (724) 682-7994, e-mail ackermanm@firstenergycorp.com, or at the letterhead address above.

Sincerely,

L. W. Pearce

L. William Pearce
Site Vice President

Attachments: Project Maps (Attachment 1)

L-03-086
Page 4

bc: G. DeCamp (CNS)
T. Grenci (CNS)
M. S. Ackerman (3 copies)
Central File

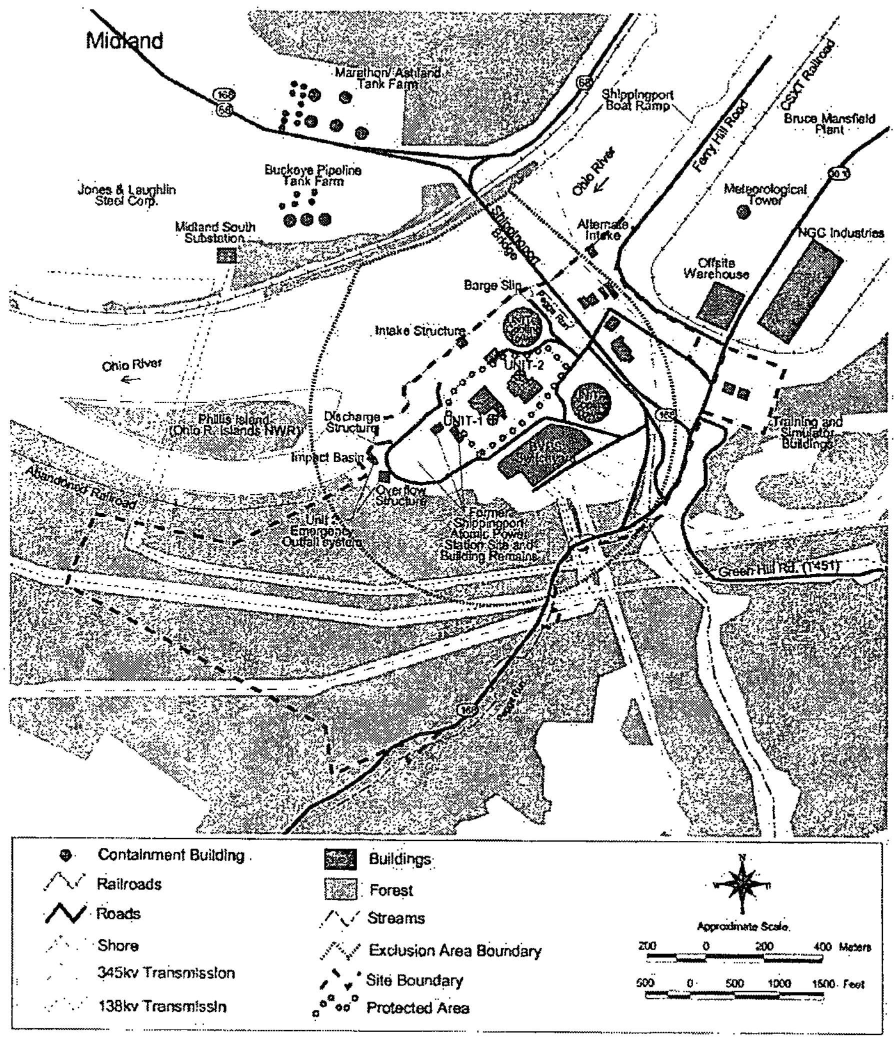
ATTACHMENT 1

PROJECT MAPS

L-03-086
Page 1

FIGURE 1

BEAVER VALLEY POWER STATION SITE MAP



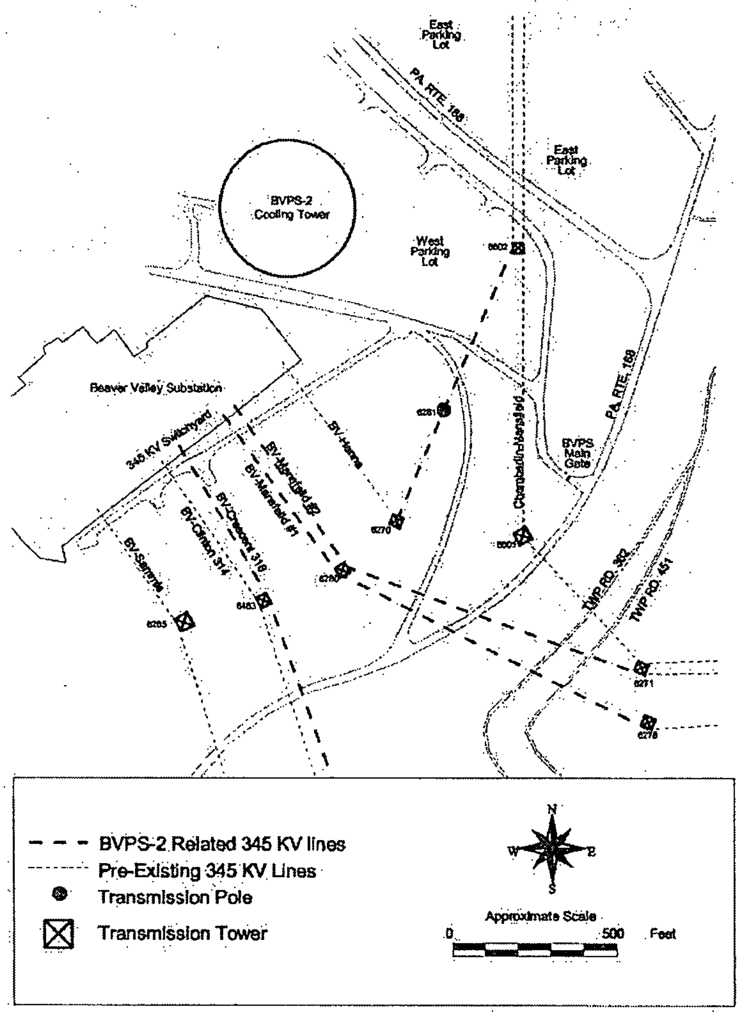
BVPS LRA Environmental Review
Project Maps

Att. 1-1

L-03-086
Page 2

FIGURE 2

345 kV RECONFIGURATIONS
FOR BEAVER VALLEY POWER STATION UNIT 2



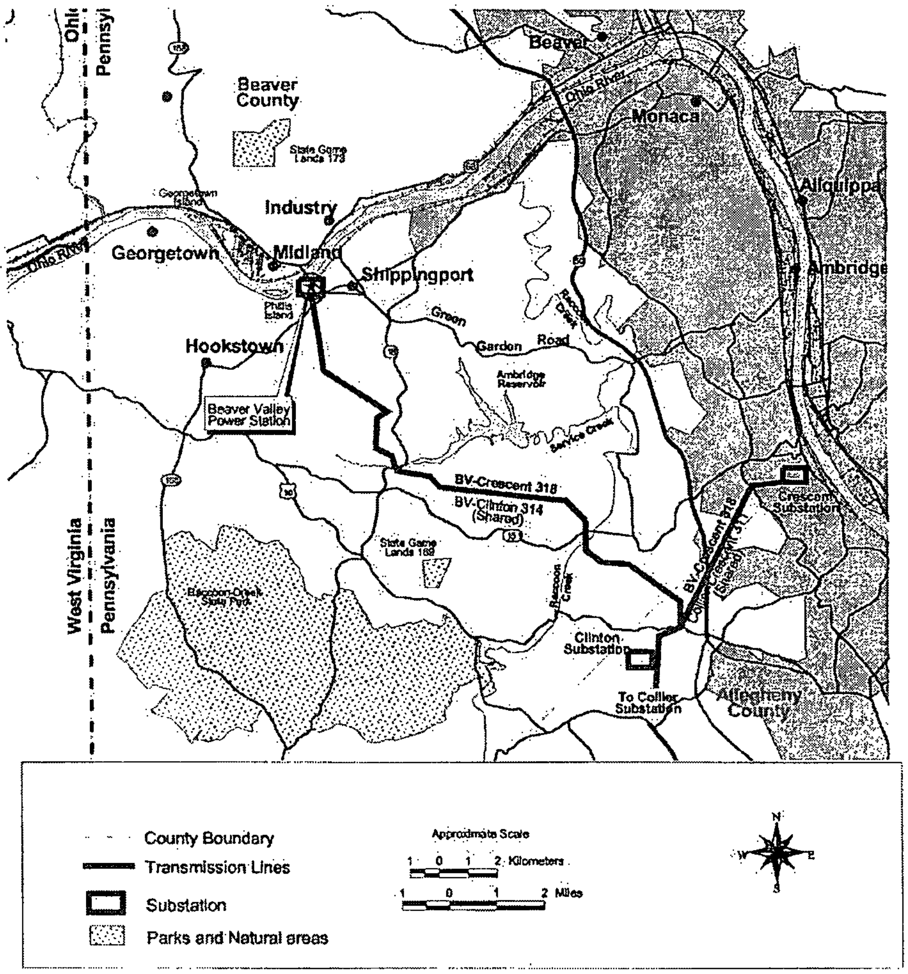
BVPS LRA Environmental Review Project Maps

Att. 1-2

L-03-086
Page 3

FIGURE 3

BEAVER VALLEY-CRESCENT LINE 318 CORRIDOR



BVPS LRA Environmental Review Att. 1-3
Project Maps

Commonwealth of Pennsylvania
Pennsylvania Historical and Museum Commission
Bureau for Historic Preservation
Commonwealth Keystone Building, 2nd Floor
400 North Street
Harrisburg, PA 17120-0093

November 19, 2003

L. William Pearce
FENOC, Beaver Valley Power Station
P O Box 4
Shippingport, PA 15077-0004

TO EXPEDITE REVIEW USE
BHP REFERENCE NUMBER

Re: ER 85-0426-007-C
NRC: Beaver Valley Power Station License Renewal Project
Shippingport, Beaver County

Dear Mr. Pearce:

The Bureau for Historic Preservation (the State Historic Preservation Office) has reviewed the above named project in accordance with Section 106 of the National Historic Preservation Act of 1966, as amended in 1980 and 1992, and the regulations (36 CFR Part 800) of the Advisory Council on Historic Preservation as revised in 1999. These requirements include consideration of the project's potential effect upon both historic and archaeological resources.

Your request does not include sufficient information. We are unable to proceed with our review for historic structures until the information on the attached form is provided.

There is a high probability that prehistoric and historic archaeological resources are located in this project area. In our opinion, the activity described in your proposal should have no effect on such resources. Should the scope of the project be amended to include additional ground disturbing activity this office should be contacted immediately and a Phase I Archaeological Survey may be necessary to locate all potentially significant archaeological resources.

If you need further information in this matter please consult Susan Zacher at (717) 783-9920.

Sincerely,

K. W. Carr

Kurt W. Carr, Chief
Division of Archaeology &
Protection

Enclosure
KWC/smz

PENNSYLVANIA HISTORICAL AND MUSEUM COMMISSION (PA 11/99)
BUREAU FOR HISTORIC PRESERVATION: INFORMATION REQUEST SHEET
(Please supply items checked below for PHMC to proceed with review)

85-0426-007-C

PROJECT INITIATION

( )A. FUNDING/PERMITTING/LICENSING/APPROVAL PROGRAM
( ) 1. Contact person for federal/state/local agency, address, phone number.
( ) 2. Letter from federal agency initiating consultation, or a letter from federal agency authorizing an alternate agency or a consultant to initiate consultation.
( ) 3. Identify the Federal/State Agency and funding program or permit/license.
( ) 4. Identification of all Federal agencies involved in project.
( ) 5. Designated "lead" Federal Agency in complex or multi-agency project.

( )B. PROJECT DESCRIPTION
( ) 1. Narrative description of the project and related actions resulting from the project.
( ) 2. Proposed boundary of the project's Area of Potential Effect (APE) (remember to consider visual impacts)
( ) 3. Description and Justification of selection of the Area of Potential Effect
( ) 4. Plans of existing conditions (as-built or as-found)
( ) 5. Preliminary drawings or plans (floor plans, elevations, specifications)
( ) 6. Work write-ups
( ) 7. Plans and specifications

(X) C. PROJECT LOCATION
(X) 1. U.S.G.S. 7.5 min. series quadrangle with the PROJECT LOCATION(S) AND LIMITS CLEARLY MARKED using a colored pen. Please include name of the quadrangle
( ) 2. U.S.G.S. 7.5 min. series quadrangle with Area of Potential Effect marked (potential area of direct effect can be delineated inside area of indirect effect)
( ) 3. Street map (for properties in densely populated areas)
( ) 4. Street map showing location and historic district boundaries (if appropriate)
( ) 5. Street address of property
( ) 6. Municipality in which project is located (not mailing address location)

(over)

( ) D. PROJECT SIZE (supply as appropriate for project)
( ) 1. Acreage of project area
( ) 2. Miles/feet of project and right-of-way width
( ) 3. Extent and nature of ground disturbing activities (i.e. grading, trenching, foundation excavation)

(X) E. PHOTOGRAPHS (no Polaroids, copies or scanned images)
(X) 1. Exterior of building(s) in project area
( ) 2. Interior of building(s) in project area
( ) 3. Interior of building(s) illustrating the proposed work areas/features
( ) 4. Buildings, streetscape, setting of features in Area of Potential Effect (APE)
( ) 5. Views of project site
( ) 6. Other________________

PUBLIC PARTICIPATION

( ) 1. Measures which will be/or have been taken to identify consulting parties.
( ) 2. List of proposed consulting parties.
( ) 3. Measures which will be/or have been taken to notify and involve the public.

RESOURCE IDENTIFICATION, EVALUATION AND PROJECT EFFECT

(X) A. Cultural Resource Identification
( ) 1. Description of methodology used for identification and sources examined.
( ) 2. Plan proposed for identification of historical (including historic districts, buildings, structures, objects) and archaeological resources and proposed methodology to be used.
(X) 3. Pennsylvania Historic Resource form(s) for all properties 50 years or older and potentially eligible for the National Register identified in the APE.
( ) 4. Historical background/context report/information for historic resources identified.
( ) 5. Pennsylvania Archaeological Site Survey form(s) (P.A.S.S) for archaeological sites identified in surveys of APE.
( ) 6. Phase I, II, III Archaeological Survey Reports
( ) 7. 5 Copies of Final Phase I, II, III Archaeological Survey Report(s) (4 bound and 1 unbound copies)

(X) B. Evaluation of Project Effect on Cultural Resources (Physical, visual, atmospheric, direct and indirect, secondary)

) C. Other:________________

____

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

L. William Pearce
Site Vice President

724-682-5234
Fax: 724-643-8069

February 3, 2004
L-04-013

Mr. Kurt W. Carr
Chief, Division of Archeology & Protection
Bureau for Historic Preservation
Pennsylvania Historical and Museum Commission
Commonwealth Keystone Building, 2nd Floor
400 North Street
Harrisburg, PA 17120-0093

Subject: Beaver Valley Power Station License Renewal Project
Historic Structures Information

References: Letter L-03-086, L. William Pearce, BVPS Site Vice President, FENOC, to Ms. Jean Cutler, State Historic Preservation Officer, Bureau for Historic Preservation, Pennsylvania Historical and Museum Commission, September 8, 2003.

Letter ER 85-0426-007-C, Kurt W. Carr, Chief, Division of Archeology and Protection, Bureau for Historic Preservation, Pennsylvania Historical and Museum Commission, November 19, 2003.

Dear Mr. Carr:

Thank your for your response dated November 19, 2003, to FirstEnergy Nuclear Operating Company's (FENOC's) preliminary draft assessment of potential impacts of Beaver Valley Power Station (BVPS) license renewal on historic and archeological resources. In your letter, you requested additional information about the BVPS license renewal project and historic resources in the project area to enable completion of the Bureau for Historic Preservation's review for historic structures. Information needs were clarified in a follow-up telephone discussion between Ms. Susan Zacher of your office and Mr. Mark Ackerman, our license renewal project manager, in December 2003.

As indicated in our preliminary assessment and follow-up discussion with Ms. Zacher, environmental reviews conducted as part of initial licensing of the two BVPS units indicated that no significant adverse impacts on historic and archeological resources would result from their operation. Renewal of the BVPS operating licenses for the units by the U.S. Nuclear Regulatory Commission (NRC) would provide the opportunity to extend their operation for up to an additional 20 years beyond the current license expiration dates. However, extended operation of the units would continue to be subject to all applicable federal, state, and local laws and regulations. In addition, FENOC has no plans for major refurbishment or significant land disturbing activity associated with license renewal. Therefore, no incremental impact on archeological or historic resources would result from BVPS license renewal.

Based on our understanding of information needs from your initial request and follow-up discussion, we are providing a map of the BVPS site on a U.S. Geological Survey topographic base (Attachment A), additional information about the Shippingport Atomic Power Station (SAPS, see Attachment B), remains of which lie within the boundary of the BVPS site, and recent photographs of SAPS buildings or remnants thereof (Attachment C). FENOC understands that the SAPS property is considered by the Pennsylvania Bureau of Historic Preservation to be eligible for listing on the National Register of Historic Places but no eligibility determination has been undertaken on the federal level by the U.S. Department of Interior. FirstEnergy has no plans to pursue listing of the property.

As indicated in Attachment B, the U.S. Department of Energy (DOE) completed decommissioning of SAPS in 1990. These activities involved removal of all fluids, piping, equipment, components, structures, and wastes having radioactivity levels above that required by DOE for unrestricted use of the site. The environmental impacts of decommissioning activities were addressed in a DOE environmental impact statement (DOE/EIS-0080F, May 1982) and subsequent record of decision (Federal Register, Vol. 47, No. 161, p. 36276, August 19, 1982).

SAPS buildings or remnants thereof that currently exist are shown in Attachment C. Of these, two warehouses (Photos 1 and 2) and a consumables storage building (Photo 9) are currently in active use in support of BVPS operations. The remainder are not actively maintained or used to support BVPS plant operations. Security requirements preclude access to the BVPS site, including the former SAPS site area, by the general public.

We hope this additional information fulfills the Bureau's needs in completing its impact review with respect to historic structures. Please address any comments or questions you may have to Mr. Mark Ackerman, License Renewal Project Manager, by telephone at (724) 682-7994, e-mail ackermanm@firstenergycorp.com, or at the letterhead address above.

Sincerely,

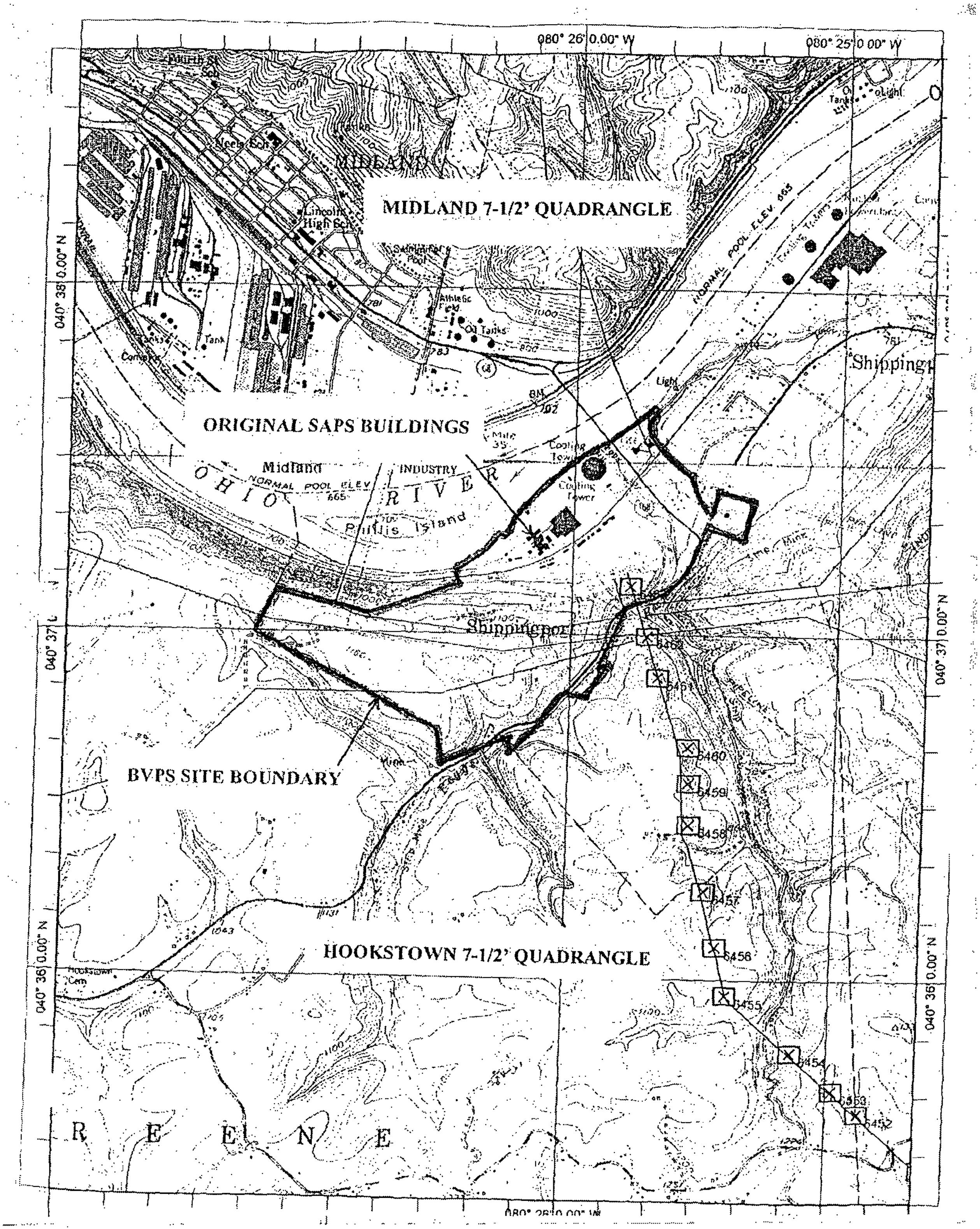
L. W. Pearce

L. William Pearce

cc: Ms. Jean Cutler, State Historic Preservation Officer

ATTACHMENT A

BEAVER VALLEY POWER STATION SITE MAP


MIDLAND 7-1/2' QUADRANGLE
ORIGINAL SAPS BUILDINGS
BVPS SITE BOUNDARY
HOOKSTOWN 7-1/2' QUADRANGLE
OHIO RIVER
Shippingport
Phillis Island
Midland
080° 26' 0.00" W
080° 25' 0.00" W
040° 38' 0.00" N
040° 37' 0.00" N
040° 36' 0.00" N
G R E E N E

ATTACHMENT B

SHIPPINGPORT ATOMIC POWER STATION FACT SHEET

FENOC
FirstEnergy Nuclear Operating Company

FACT SHEET

SUBJECT: **Shippingport Atomic Power Station**

DATE: **August 27, 2001**

SHIPPINGPORT ATOMIC POWER STATION
A Historical Perspective

Shippingport Atomic Power Station was the first large-scale, central station, nuclear electric generating plant in the United States.

BACKGROUND – In 1953, the U.S. Atomic Energy Commission (AEC) made the decision to construct the nuclear power plant using a pressurized light water reactor. This project was to confirm the practicability of nuclear power for civilian purposes and to provide the technology necessary for design and operation of large-scale central station nuclear power plants. Because of its extensive naval work with pressurized light water reactors for ship propulsion, the AEC's Division of Naval Reactors, headed by Admiral H.G. Rickover, was assigned the responsibility for the pressurized water reactor project. Duquesne Light Company was selected to take part in this project on the basis of their proposal, one of nine major bids made to the AEC.

HISTORICAL SIGNIFICANCE – The building of the first commercial-sized nuclear electric generating station was of such national importance that the President of the United States, Dwight D. Eisenhower, participated via electronic communications in both the groundbreaking and the dedication of Shippingport. Shippingport established itself as a source of valuable information on reactor technology for the entire nuclear power industry. It also served as a training ground for many key personnel in nuclear generating plants throughout the world.

OWNERSHIP-OPERATION – The Shippingport station was operated by Duquesne Light under contract with the U.S. Department of Energy (DOE). Duquesne Light owned the conventional electric generating portion of the plant. The reactor and steam-generating portions of the station were owned by the DOE. The nuclear portion of the plant was designed by Westinghouse Electric Corporation's Bettis Atomic Power Laboratory under the direction of and in technical cooperation with Naval Reactors. Duquesne Light supplied the land, built the turbine-generator and contributed $5 million to the design and construction of the nuclear portion of the plant. To run the turbine-generator, Duquesne Light purchased the steam produced by the nuclear portion of the plant.

LIGHT WATER BREEDER REACTOR CORE (LWBR) – In 1977, the Department of Energy modified the Shippingport Station reactor to accept a light water breeder core. This was done to demonstrate that breeding of nuclear fuel can be achieved in a light water reactor system using a thorium-232/uranium 233 fuel system. The LWBR core at Shippingport was installed by the Bettis Atomic Power Lab under the technical direction of the DOE.

RETIREMENT AND DECOMMISSIONING – With the completion of the LWBR demonstration program on October 1, 1982, the DOE permanently closed the station. Reactor operations were ceased. The decommissioning activities began in 1985 under the supervision of the Department of Energy Office of Remedial Action and Waste Technology and were completed in 1990.

TECHNICAL FACTS – Shippingport consisted of a pressurized water reactor and its associated systems, four steam generators heated by the reactor, a single turbine-generator and associated systems, a radioactive waste disposal system, laboratories, shops and administrative facilities.

Station Size – Shippingport was designed to supply a minimum electric output of 60,000 kilowatts. Because of the probability that its output would be greater than originally anticipated, and to allow for increased output from future nuclear fuel loadings, the turbine-generator was built with a capacity of 100,000 kilowatts.

Groundbreaking – Groundbreaking ceremonies were held on September 6, 1954.

Reactor Operation – The reactor was first put into operation on December 2, 1957. The first electric power was produced on December 18, 1957.

Dedication Ceremonies – The dedication of the plant took place on May 26, 1958.

Change in Power Output – In 1965, the plant's electric generating capability was increased to 100,000 kilowatts through the installation of a larger and more efficient reactor core. Upon installation of the LWBR core in 1977, the plant net output was restored to the original 60,000 kilowatt capacity.

Electric Output – During the life of Shippingport's operation, from 1957 to October 1982, the plant produced over 7 billion kilowatt-hours of electricity.

President Eisenhower participating in the Shippingport dedication ceremony.

* *Information reprinted from SAPS Fact Sheet, Duquesne Light Company, May 1983*

ATTACHMENT C

SHIPPINGPORT ATOMIC POWER STATION (SAPS) BUILDINGS AND BUILDING REMNANTS PHOTOGRAPHS 1 THROUGH 10 (DECEMBER 2003)

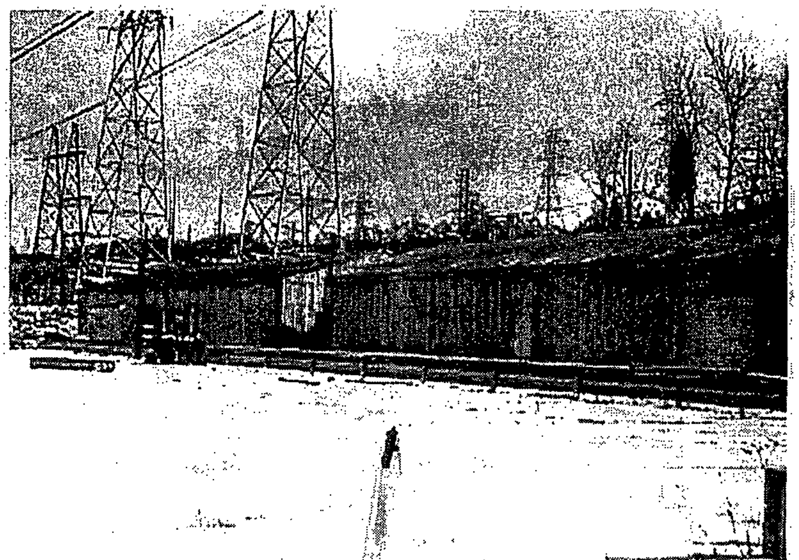


Photo 1. SAPS warehouses

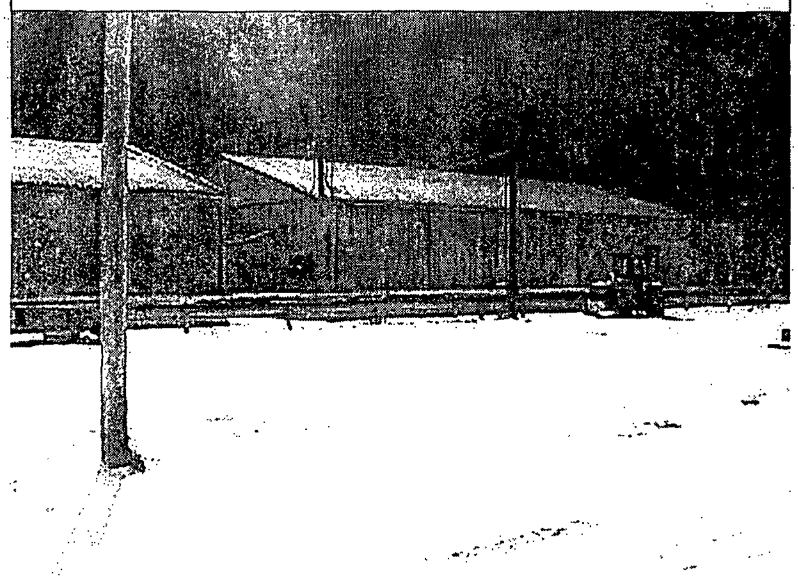


Photo 2. SAPS warehouses (same as Photo 1)

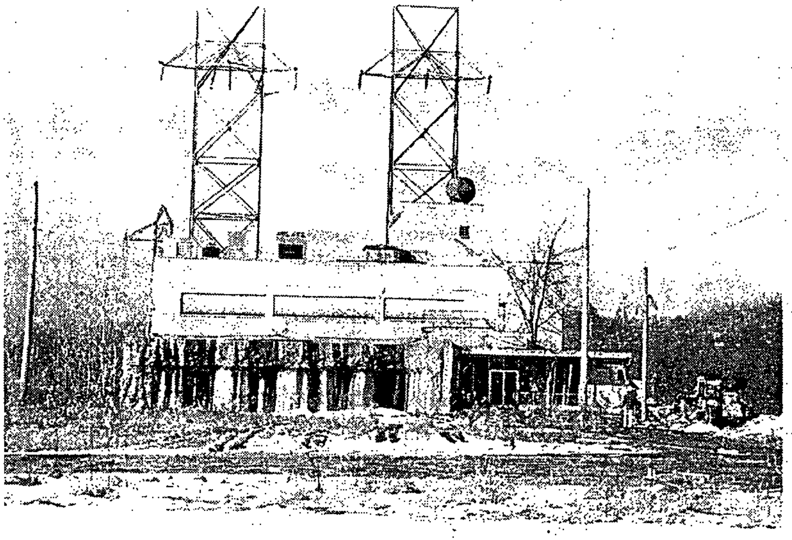


Photo 3. SAPS administration building. Control room is located in this building, behind on lower level. Auxiliary chamber enclosure wall is visible in foreground.

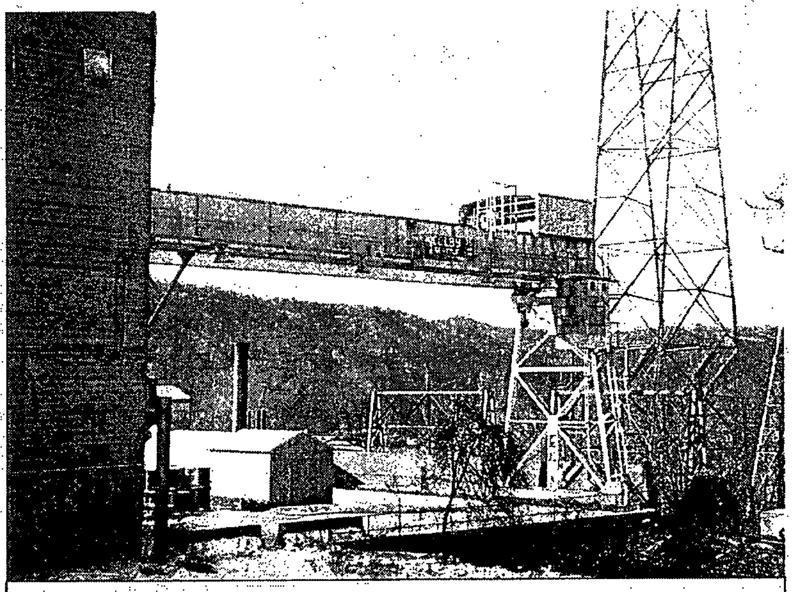


Photo 4. SAPS turbine deck crane

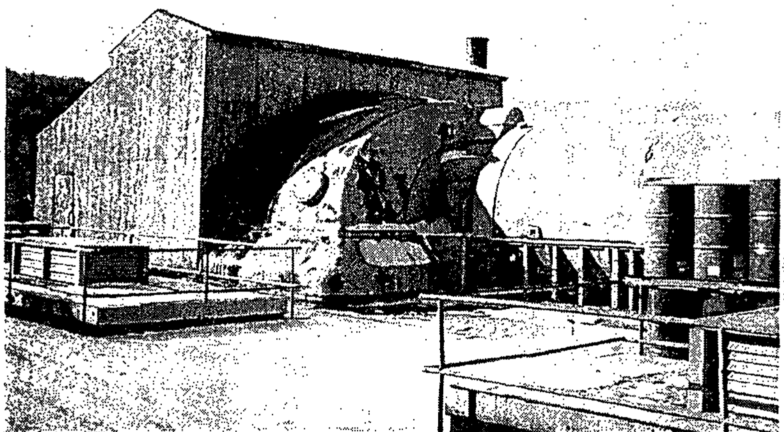
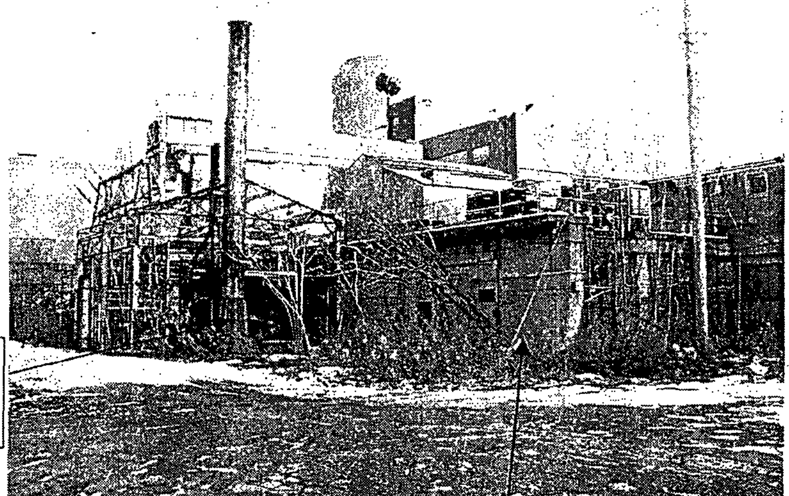


Photo 5. SAPS turbine-generator. Plywood structure was built after plant was decommissioned.



SAPS auxiliary boiler

Photo 6. SAPS turbine building (water treatment area)
Note: Cooling tower in background is part of the Beaver Valley Power Station.

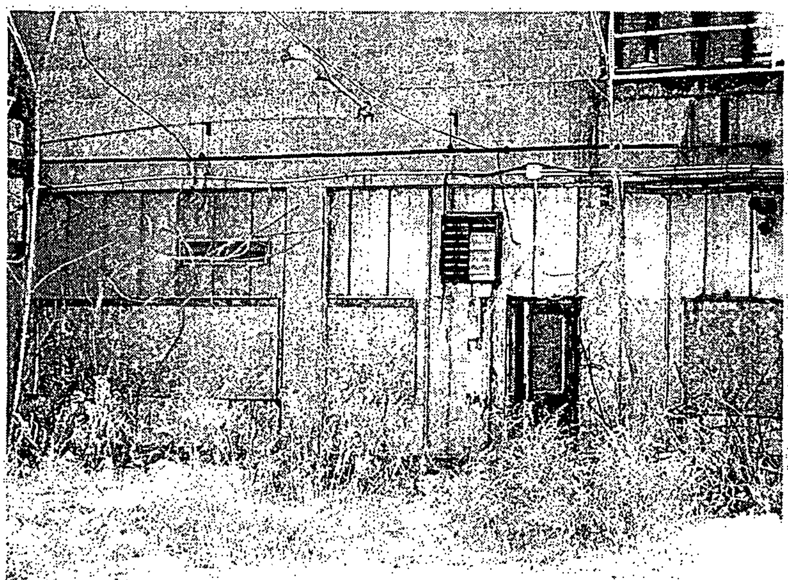


Photo 7. SAPS turbine building

Photo 8. SAPS auxiliary chamber enclosure wall

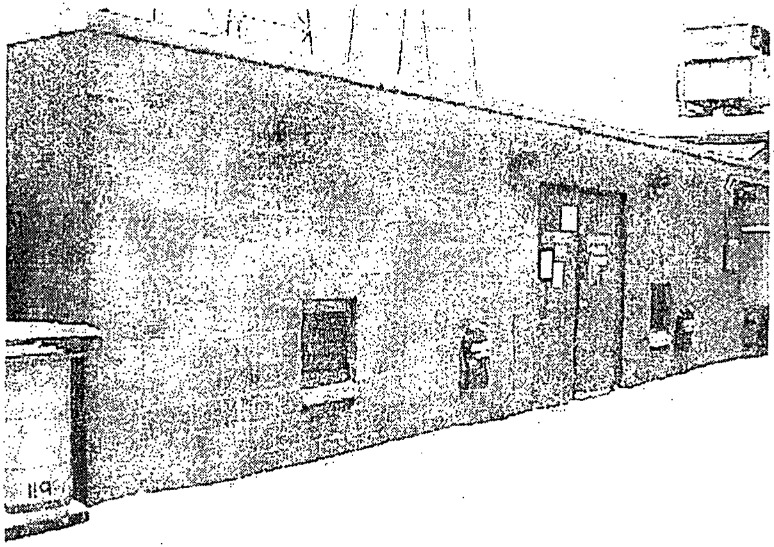


Photo 9. SAPS water treatment consumables building

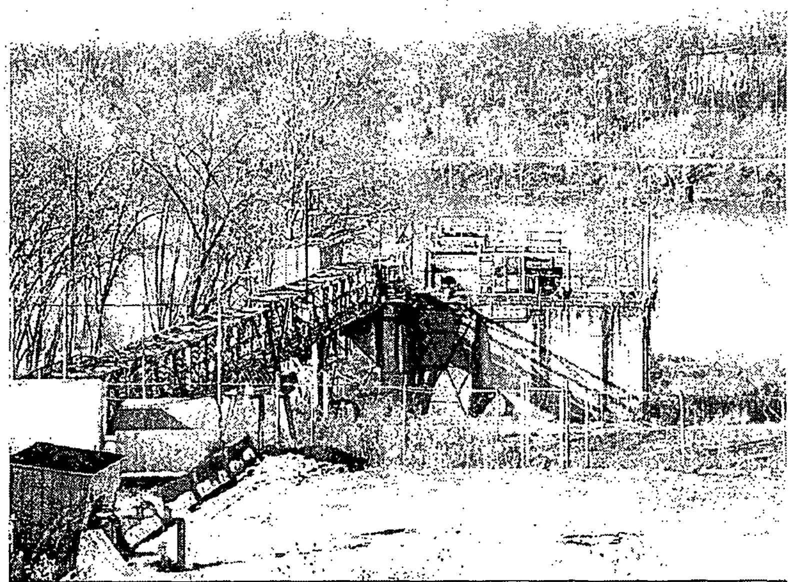


Photo 10. SAPS cooling water intake structure

Commonwealth of Pennsylvania
Pennsylvania Historical and Museum Commission
Bureau for Historic Preservation
Commonwealth Keystone Building, 2nd Floor
400 North Street
Harrisburg, PA 17120-0093

March 12, 2004

L. William Pearce
FirstEnergy Nuclear Operating Company
Beaver Valley Power Station
Route 168, P.O. Box 4
Shippingport, PA 15077-0004

Re: File No. ER 85-0426-007-D
NRC Preliminary Draft Assessment:
Beaver Valley Power Station License
Renewal Project, Shippingport
Beaver County

Dear Mr. Pearce:

The Bureau for Historic Preservation (the State Historic Preservation Office) has reviewed the above named project in accordance with Section 106 of the National Historic Preservation Act of 1966, as amended in 1980 and 1992, and the regulations (36 CFR Part 800) of the Advisory Council on Historic Preservation. These requirements include consideration of the project's potential effect upon both historic and archaeological resources.

Based on our survey files, which include both archaeological sites and standing structures, there are no National Register eligible or listed historic or archaeological properties in the area of this proposed project. Therefore, your responsibility for consultation with the State Historic Preservation Office for this project is complete. Should you become aware, from any source, that historic or archaeological properties are located at or near the project site, please notify the Bureau for Historic Preservation at (717) 783-8946.

Sincerely,

Kurt W. Carr

Kurt W. Carr, Chief
Division of Archaeology &
Protection

KWC/tmw

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

December 4, 2006
BVLR-ENV-06-012

Ms. Kathleen McGinty, Secretary
Pennsylvania DEP
16th Floor, Rachel Carson State Office Bldg.
P. O. Box 2063
Harrisburg, PA 17105-2063

Subject: Environmental Review for Beaver Valley Power Station License Renewal Project

Dear Ms. McGinty:

In 2002, FirstEnergy Nuclear Operating Company (FENOC) requested your input to the Beaver Valley Power Station (BVPS) license renewal environmental review. FENOC is currently preparing a final application for submittal to the U.S. Nuclear Regulatory Commission (NRC). Upon successful acceptance by the NRC, the operating licenses for the two nuclear power generating units at BVPS, located in Beaver County, Pennsylvania will be renewed. You are likely aware that the operating licenses for many U.S. nuclear power plants have been recently renewed and that applications for license renewal of numerous other plants have been submitted to the NRC and are undergoing review. Upon issuance of the renewed operating licenses the life of the BVPS units will be extended for an additional 20 years (i.e., until 2036 and 2047 for Units 1 and 2, respectively).

In addition to detailed safety reviews, the license renewal process involves a thorough review of potential environmental impacts in accordance with provisions of the National Environmental Policy Act (NEPA). The attached fact sheet provides an overview of the process and associated environmental review activities to be conducted by FENOC and the NRC for the BVPS License Renewal. In brief, the NRC has prepared a generic environmental impact statement (GEIS) that addresses environmental impacts of license renewal on the basis of a review of plants nationwide. Detailed environmental reviews of individual plants, such as BVPS, include preparation of an environmental report (ER) by the applicant and a site-specific supplement to the GEIS by the NRC. The latter documents must include impact assessments for site-specific environmental issues that were not resolved generically by the NRC in the GEIS. They also must identify any known "new and significant information," i.e., new and significant environmental issues or impacts not recognized as such by the NRC in the GEIS, and the NRC's codified findings from the GEIS (10 CFR 51.53). In accordance with NEPA, the NRC's process for developing the site-specific supplements includes substantial opportunity for participation by agencies and the public, including the opportunity to formally comment on the scope of the NRC's site-specific supplement to the GEIS and the adequacy of that document.

Page Two
November 20, 2006

During the August 2002 through December 2004 period, agencies and stakeholders – including your group – did not identify any new and significant information or environmental impacts beyond those identified by the NRC. Nonetheless, the BVPS License Renewal Environmental Review Team would appreciate your early and active participation in the license renewal environmental review process for BVPS. In particular, we would welcome any new questions or concerns your agency may have developed regarding the environmental implications of BVPS license renewal, as well as any information that your agency may consider to be potentially "new and significant." These efforts will help ensure that the ER we prepare is complete and up-to-date. In this regard, if you believe it necessary, we would be pleased to meet with your agency representative(s) to discuss the BVPS license renewal environmental review in detail.

Please feel free to contact Mr. Clifford Custer, License Renewal Project Manager at 724-682-7139, or for environmental-specific issues, Mr. Michael Banko at 724-682-4117. Please address your agency's interest in a meeting, and any questions or concerns about the environmental review to:

Mr. Clifford I. Custer
BVPS License Renewal Project Manager
Beaver Valley Power Station (Mail Stop BV-SIM2)
P.O. Box 4
Route 168 W
Shippingport, PA 15077-0004

Tel.: 724-682-7139
Email: custerc@firstenergycorp.com

Thank you on behalf of FENOC and the BVPS License Renewal Environmental Review Team.

Sincerely,

James H. Lash
Site Vice-President

Attachment

cc: C. I. Custer
G. A. Dunn
M. D. Banko
BVRC: ***Keyword(s) – License Renewal Environmental Report***

ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

Background

FirstEnergy Corporation owns the Beaver Valley Power Station (BVPS); a two-unit nuclear power plant located on a 453-acre site on the Ohio River in Shippingport Borough, Beaver County, Pennsylvania. Upon completion of our full potential project, the capacity will approximate 924 MWe at Unit 1, 2 918 MWe at Unit 2, for a total of 1842 MWe for the site. BVPS features a close-cycle cooling system that uses two natural draft cooling towers. The Ohio River (New Cumberland Pool) provides the source of cooling tower makeup water and receives the cooling tower blowdown discharge. Transmission lines from BVPS consist of six 345-kV lines, two of which (BV-Sammis and BV-Hanna) extend into West Virginia and/or Ohio, and seven 138-kV lines, all in Pennsylvania.

The initial 40-year operating licenses for BVPS Units 1 and 2 expire in 2016 and 2027, respectively. In keeping with continued efforts to ensure a safe, reliable, and economical supply of energy to its customers, in August 2007 FirstEnergy plans to submit an application to the U.S. Nuclear Regulatory Commission (NRC) for a renewed license. The renewed license would authorize operation of the units for 20 years beyond their current license expiration dates; i.e., until 2036 and 2047, respectively.

The NRC license renewal application process involves a thorough technical evaluation of plant systems, structures, and components to assess the effects of aging, as well as development of measures to manage these effects to ensure continued safe operation through the period of extended operation. In accordance with the National Environmental Policy Act (NEPA), the license renewal process also involves an assessment of potential environmental impacts associated with extended operation of the plant; major plant refurbishments, if any, within the scope of license renewal; and associated transmission lines considered within the scope of license renewal.

The NRC's NEPA evaluation process provides substantial opportunities for input from stakeholders, including federal, state, and local agencies responsible for resources potentially affected by extended operation and associated major refurbishments. FirstEnergy previously met with interested agencies regarding potential environmental impacts related to extended operation, and is willing to do so again. Additionally, the NRC is specifically obligated to consult with the U.S. Fish and Wildlife Service and the State Historic Preservation Officers of Pennsylvania and other potentially affected states regarding potential impacts to threatened or endangered species and cultural resources, respectively.

FirstEnergy prepared this overview of the license renewal environmental review process to familiarize agency representatives with this process and facilitate active agency participation. Detailed information is available from the NRC license renewal website (http://www.nrc.gov/reactors/operating/licensing/renewal.html).

The License Renewal Environmental Review Process

The NRC requires applications for renewal of nuclear power plant operating licenses to include an environmental report (ER) which addresses the potential environmental impacts of license renewal and the alternatives to license renewal. To improve efficiency of the environmental review process for these applications, the NRC has prepared and issued a generic environmental impact statement (GEIS), *Generic Environmental Impact Statement for the License Renewal of*

ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

Nuclear Power Plants (i.e., NUREG-1437) and amended its environmental protection regulations in 10 CFR 51, Subpart A. In the GEIS, the NRC identified and evaluated 92 issues, representing a full range of potential environmental impacts that could result from license renewal, including impacts from any necessary plant refurbishment activities and impacts from plant operation beyond the current 40-year operating license term. The NRC designated 69 of the issues as Category 1, based on the following criteria:

a. the impacts associated with the issue apply either to all plants or to plants having a specific cooling system or other specified plant or site characteristic;

b. a single significance level (i.e., small, medium, or large) has been assigned to the impacts; and

c. additional plant-specific mitigation measures were likely to not be sufficiently beneficial to warrant implementation.

Environmental impacts associated with these Category 1 issues were thus identified, analyzed, and resolved in the GEIS. However, twenty-one (21) of the 92 total issues did not meet one or more of the Category 1 criteria and, were deemed Category 2 issues. Because these Category 2 issues could not be generically resolved, the NRC requires that they be addressed on a site-specific basis in the applicant's ER [10 CFR 51.53(c) and associated Appendix B, Table B-11].

To ensure thorough analysis of all potential environmental impacts associated with license renewal, the NRC requires that applicants identify in the ER any "new and significant information" regarding the environmental impact of license renewal of which the applicant is aware. Such information includes potentially significant environmental issues the NRC did not consider in the GEIS and information that may lead to a different conclusion than was documented in the GEIS and codified in Table B-1 of the NRC regulations as cited above. In the course of developing the ER, applicants for a renewed operating license routinely consult with resource agencies. These consultations are undertaken to familiarize the agencies with the project, identify agency concerns, and obtain pertinent resource information, including any new and potentially significant information, as needed to ensure a complete and accurate application.

The NRC addresses any new and significant and site-specific issues, that are not resolved in the GEIS, in a Supplemental Environmental Impact Statement (SEIS). In preparing the SEIS, the NRC will use information submitted by FE and:

1. Solicits stakeholder input from media sources and at public meetings to finalize the SEIS scope.

2. Consults with resource agencies to determine agency concerns and obtain additional information.

3. Prepares a Draft SEIS on the basis of independent analysis, using input from the applicant, resource agencies, and the public.

4. Solicits stakeholder comments on the Draft SEIS in the media and at public meetings.

5. Prepares the Final SEIS on the basis of comments received.

The ER will address applicable site-specific environmental issues related to extended operation of BVPS and other appropriate topics as specified in 10 CFR 51.53(c), including:

2

ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

- Applicable Category 2 issues, including potential impact on water use.
- Ecological resources, land use, and socio-economics.
- Environmental justice.
- New and significant issues, if applicable.
- Alternatives to license renewal (e.g., generation alternatives).
- Historical and archaeological considerations

The NRC will establish a schedule for SEIS preparation and related activities once the application for BVPS has been submitted.

Environmental Review Activities For BVPS

FirstEnergy has conducted data gathering efforts as part of the ER development effort. Beginning in July 2002, FirstEnergy met with interested environmental resource agencies to familiarize them with the NRC license renewal process and the BVPS license renewal project, to obtain input. As previously mentioned and as a matter of statutory obligation or policy, the NRC is expected to request informal consultations with some agencies at the SEIS stage (e.g., U.S. Fish and Wildlife Service, PA Historic Preservation Office, PA Fish and Boat Commission, PA Game Commission, PA Department of Conservation & Natural Resources, PA Department of Health, Ohio Department of Natural Resources, West Virginia Division of Natural Resources). FirstEnergy specifically requested and received written input from these to include in the ER and facilitate these later consultations with the NRC.

Based on this and other communications, FE will follow up with them if requested.

We also understand that previous reviews for threatened or endangered species may not reflect current conditions. Therefore, in response to previous communications with the responsible agencies, since 2002, FirstEnergy has and will continue to conduct an annual review, through the Pennsylvania Natural Diversity Index (PNDI), in accordance with current Pennsylvania procedures.

Docketed Examples Available for Review

Various docketed GEIS and SEISs associated with nuclear plants requesting renewed operating licenses are available from the NRC as NUREG 1437 and associated supplements located at http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff. NRC regulations are readily available at http://www.nrc.gov/reading-rm/doc-collections/cfr/.

3

Pennsylvania Department of Environmental Protection

Rachel Carson State Office Building
P.O. Box 2063
Harrisburg, PA 17105-2063

December 15, 2006

Secretary 717-787-2814

Mr. James H. Lash
Site Vice-President
Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

Dear Mr. Lash:

Thank you for your recent letter regarding the environmental review of the Beaver Valley Power Station (BVPS) license renewal project. As of now, the Department of Environmental Protection (DEP) has not identified any new and significant information or environmental impacts beyond those identified by the Nuclear Regulatory Commission's (NRC) Generic Environmental Impact Statement (GEIS) for license renewal. However, DEP will review the site-specific environmental report and the supplements to the GEIS for BVPS and will provide input into the NRC review and approval process, as appropriate.

Thank you again for your initiative and willingness to solicit input from DEP regarding BVPS license renewal environmental review process.

Sincerely,

Kathleen A. McGinty
Secretary

Mr. James H. Lash - 2 -

bcc: Secretary Log Letter Lash #24353954
WARM
Dave Allard
Rich Janati
Larry Ryan
G. A. Dunn
Clifford Custer
Michael Banko
BRP File Copy

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

December 4, 2006
BVLR-ENV-06-015

Mr. Ronald Schwartz
Assistant Regional Director
Pennsylvania DEP
400 Waterfront Drive
Pittsburgh, PA 15222

Subject: Environmental Review for Beaver Valley Power Station License Renewal Project

Dear Mr. Schwartz:

In 2002, FirstEnergy Nuclear Operating Company (FENOC) requested your input to the Beaver Valley Power Station (BVPS) license renewal environmental review. FENOC is currently preparing a final application for submittal to the U.S. Nuclear Regulatory Commission (NRC). Upon successful acceptance by the NRC, the operating licenses for the two nuclear power generating units at BVPS, located in Beaver County, Pennsylvania will be renewed. You are likely aware that the operating licenses for many U.S. nuclear power plants have been recently renewed and that applications for license renewal of numerous other plants have been submitted to the NRC and are undergoing review. Upon issuance of the renewed operating licenses the life of the BVPS units will be extended for an additional 20 years (i.e., until 2036 and 2047 for Units 1 and 2, respectively).

In addition to detailed safety reviews, the license renewal process involves a thorough review of potential environmental impacts in accordance with provisions of the National Environmental Policy Act (NEPA). The attached fact sheet provides an overview of the process and associated environmental review activities to be conducted by FENOC and the NRC for the BVPS License Renewal. In brief, the NRC has prepared a generic environmental impact statement (GEIS) that addresses environmental impacts of license renewal on the basis of a review of plants nationwide. Detailed environmental reviews of individual plants, such as BVPS, include preparation of an environmental report (ER) by the applicant and a site-specific supplement to the GEIS by the NRC. The latter documents must include impact assessments for site-specific environmental issues that were not resolved generically by the NRC in the GEIS. They also must identify any known "new and significant information," i.e., new and significant environmental issues or impacts not recognized as such by the NRC in the GEIS, and the NRC's codified findings from the GEIS (10 CFR 51.53). In accordance with NEPA, the NRC's process for developing the site-specific supplements includes substantial opportunity for participation by agencies and the public, including the opportunity to formally comment on the scope of the NRC's site-specific supplement to the GEIS and the adequacy of that document.

Page Two
November 20, 2006

During the August 2002 through December 2004 period, agencies and stakeholders – including your group – did not identify any new and significant information or environmental impacts beyond those identified by the NRC. Nonetheless, the BVPS License Renewal Environmental Review Team would appreciate your early and active participation in the license renewal environmental review process for BVPS. In particular, we would welcome any new questions or concerns your agency may have developed regarding the environmental implications of BVPS license renewal, as well as any information that your agency may consider to be potentially "new and significant." These efforts will help ensure that the ER we prepare is complete and up-to-date. In this regard, if you believe it necessary, we would be pleased to meet with your agency representative(s) to discuss the BVPS license renewal environmental review in detail.

Please feel free to contact Mr. Clifford Custer, License Renewal Project Manager at 724-682-7139, or for environmental-specific issues, Mr. Michael Banko at 724-682-4117. Please address your agency's interest in a meeting, and any questions or concerns about the environmental review to:

Mr. Clifford I. Custer
BVPS License Renewal Project Manager
Beaver Valley Power Station (Mail Stop BV-SIM2)
P.O. Box 4
Route 168 W
Shippingport, PA 15077-0004

Tel.: 724-682-7139
Email: custerc@firstenergycorp.com

Thank you on behalf of FENOC and the BVPS License Renewal Environmental Review Team.

Sincerely,

James H. Lash
Site Vice-President

Attachment

cc: C. I. Custer
G. A. Dunn
M. D. Banko
BVRC: *Keyword(s) – License Renewal Environmental Report*

ATTACHMENT:
License Renewal Environmental Review Process For The Beaver Valley Power Station

Background

FirstEnergy Corporation owns the Beaver Valley Power Station (BVPS); a two-unit nuclear power plant located on a 453-acre site on the Ohio River in Shippingport Borough, Beaver County, Pennsylvania. Upon completion of our full potential project, the capacity will approximate 924 MWe at Unit 1, 2 918 MWe at Unit 2, for a total of 1842 MWe for the site. BVPS features a close-cycle cooling system that uses two natural draft cooling towers. The Ohio River (New Cumberland Pool) provides the source of cooling tower makeup water and receives the cooling tower blowdown discharge. Transmission lines from BVPS consist of six 345-kV lines, two of which (BV-Sammis and BV-Hanna) extend into West Virginia and/or Ohio, and seven 138-kV lines, all in Pennsylvania.

The initial 40-year operating licenses for BVPS Units 1 and 2 expire in 2016 and 2027, respectively. In keeping with continued efforts to ensure a safe, reliable, and economical supply of energy to its customers, in August 2007 FirstEnergy plans to submit an application to the U.S. Nuclear Regulatory Commission (NRC) for a renewed license. The renewed license would authorize operation of the units for 20 years beyond their current license expiration dates; i.e., until 2036 and 2047, respectively.

The NRC license renewal application process involves a thorough technical evaluation of plant systems, structures, and components to assess the effects of aging, as well as development of measures to manage these effects to ensure continued safe operation through the period of extended operation. In accordance with the National Environmental Policy Act (NEPA), the license renewal process also involves an assessment of potential environmental impacts associated with extended operation of the plant; major plant refurbishments, if any, within the scope of license renewal; and associated transmission lines considered within the scope of license renewal.

The NRC's NEPA evaluation process provides substantial opportunities for input from stakeholders, including federal, state, and local agencies responsible for resources potentially affected by extended operation and associated major refurbishments. FirstEnergy previously met with interested agencies regarding potential environmental impacts related to extended operation, and is willing to do so again. Additionally, the NRC is specifically obligated to consult with the U.S. Fish and Wildlife Service and the State Historic Preservation Officers of Pennsylvania and other potentially affected states regarding potential impacts to threatened or endangered species and cultural resources, respectively.

FirstEnergy prepared this overview of the license renewal environmental review process to familiarize agency representatives with this process and facilitate active agency participation. Detailed information is available from the NRC license renewal website (http://www.nrc.gov/reactors/operating/licensing/renewal.html).

The License Renewal Environmental Review Process

The NRC requires applications for renewal of nuclear power plant operating licenses to include an environmental report (ER) which addresses the potential environmental impacts of license renewal and the alternatives to license renewal. To improve efficiency of the environmental review process for these applications, the NRC has prepared and issued a generic environmental impact statement (GEIS), *Generic Environmental Impact Statement for the License Renewal of*

ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

Nuclear Power Plants (i.e., NUREG-1437) and amended its environmental protection regulations in 10 CFR 51, Subpart A. In the GEIS, the NRC identified and evaluated 92 issues, representing a full range of potential environmental impacts that could result from license renewal, including impacts from any necessary plant refurbishment activities and impacts from plant operation beyond the current 40-year operating license term. The NRC designated 69 of the issues as Category 1, based on the following criteria:

a. the impacts associated with the issue apply either to all plants or to plants having a specific cooling system or other specified plant or site characteristic;

b. a single significance level (i.e., small, medium, or large) has been assigned to the impacts; and

c. additional plant-specific mitigation measures were likely to not be sufficiently beneficial to warrant implementation.

Environmental impacts associated with these Category 1 issues were thus identified, analyzed, and resolved in the GEIS. However, twenty-one (21) of the 92 total issues did not meet one or more of the Category 1 criteria and, were deemed Category 2 issues. Because these Category 2 issues could not be generically resolved, the NRC requires that they be addressed on a site-specific basis in the applicant's ER [10 CFR 51.53(c) and associated Appendix B, Table B-11].

To ensure thorough analysis of all potential environmental impacts associated with license renewal, the NRC requires that applicants identify in the ER any "new and significant information" regarding the environmental impact of license renewal of which the applicant is aware. Such information includes potentially significant environmental issues the NRC did not consider in the GEIS and information that may lead to a different conclusion than was documented in the GEIS and codified in Table B-1 of the NRC regulations as cited above. In the course of developing the ER, applicants for a renewed operating license routinely consult with resource agencies. These consultations are undertaken to familiarize the agencies with the project, identify agency concerns, and obtain pertinent resource information, including any new and potentially significant information, as needed to ensure a complete and accurate application.

The NRC addresses any new and significant and site-specific issues, that are not resolved in the GEIS, in a Supplemental Environmental Impact Statement (SEIS). In preparing the SEIS, the NRC will use information submitted by FE and:

1. Solicits stakeholder input from media sources and at public meetings to finalize the SEIS scope.
2. Consults with resource agencies to determine agency concerns and obtain additional information.
3. Prepares a Draft SEIS on the basis of independent analysis, using input from the applicant, resource agencies, and the public.
4. Solicits stakeholder comments on the Draft SEIS in the media and at public meetings.
5. Prepares the Final SEIS on the basis of comments received.

The ER will address applicable site-specific environmental issues related to extended operation of BVPS and other appropriate topics as specified in 10 CFR 51.53(c), including:

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ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

- Applicable Category 2 issues, including potential impact on water use.
- Ecological resources, land use, and socio-economics.
- Environmental justice.
- New and significant issues, if applicable.
- Alternatives to license renewal (e.g., generation alternatives).
- Historical and archaeological considerations

The NRC will establish a schedule for SEIS preparation and related activities once the application for BVPS has been submitted.

Environmental Review Activities For BVPS

FirstEnergy has conducted data gathering efforts as part of the ER development effort. Beginning in July 2002, FirstEnergy met with interested environmental resource agencies to familiarize them with the NRC license renewal process and the BVPS license renewal project, to obtain input. As previously mentioned and as a matter of statutory obligation or policy, the NRC is expected to request informal consultations with some agencies at the SEIS stage (e.g., U.S. Fish and Wildlife Service, PA Historic Preservation Office, PA Fish and Boat Commission, PA Game Commission, PA Department of Conservation & Natural Resources, PA Department of Health, Ohio Department of Natural Resources, West Virginia Division of Natural Resources). FirstEnergy specifically requested and received written input from these to include in the ER and facilitate these later consultations with the NRC.

Based on this and other communications, FE will follow up with them if requested.

We also understand that previous reviews for threatened or endangered species may not reflect current conditions. Therefore, in response to previous communications with the responsible agencies, since 2002, FirstEnergy has and will continue to conduct an annual review, through the Pennsylvania Natural Diversity Index (PNDI), in accordance with current Pennsylvania procedures.

Docketed Examples Available for Review

Various docketed GEIS and SEISs associated with nuclear plants requesting renewed operating licenses are available from the NRC as NUREG 1437 and associated supplements located at http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff. NRC regulations are readily available at http://www.nrc.gov/reading-rm/doc-collections/cfr/.

3

Pennsylvania Department of Environmental Protection

400 Waterfront Drive
Pittsburgh, PA 15222-4745

December 29, 2006

Southwest Regional Office

412-442-4189
Fax 412-442-4194

Clifford I. Custer
Beaver Valley Power Station
(Mail Stop BV-SIM2)
P. O. Box 4, Route 168 W
Shippingport, PA 15077-0004

Re: Environmental Assessment Project
Beaver Valley Power Station License Renewal
Shippingport Borough
Beaver County

Dear Mr. Custer:

DEP's regional program staff have reviewed the above project for environmental regulatory and policy requirements, and submit the following comments for your attention. These comments are only based on project information you provided, and may not be comprehensive. The applicant has the responsibility of complying with all relevant environmental laws and regulations for the project.

Watershed Management

If your license renewal project will include any new, additional, expanded, replacement and/or other structures or activities that will include work in or along watercourses, floodplains, or bodies of water, including wetlands, your project may require a Water Obstruction and Encroachment Permit, from the Permitting and technical Services Section, in DEP's Watershed Management Program. Please contact a Permitting and Technical Services representatives at 412-442-4315 for more information.

For your convenience, we have enclosed our e-Map information from our website, (http://www.dep.pa.us/external_gis/gis_home.htm) of known environmental features within the area you identified which may be of interest or concern to you with your project.

Should you have any questions or if the project is significantly modified in the future, please contact this office at the telephone number listed above.

Sincerely,

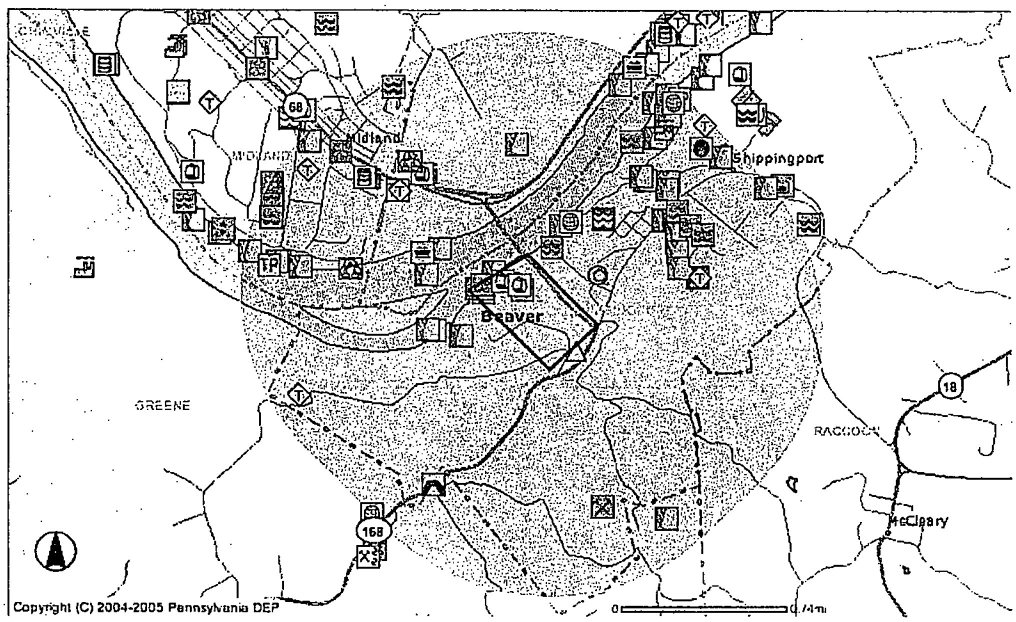
Ronald A. Schwartz

Ronald A. Schwartz, P.E.
Assistant Regional Director
Southwest Regional Office

Enclosure

An Equal Opportunity Employer   www.dep.state.pa.us   Printed on Recycled Paper

DEP eMapPA



MIDLAND AND HOOKSTOWN 7.5'

APPLICANT: **FENOC**	**BEAVER VALLEY POWER STATION** **1 Mile Radius**
LEGEND SEE ATTACHED	**PA DEP** **SOUTHWEST REGIONAL OFFICE** **BY: MARK POREMBKA** **DATE: 12/13/06**

FACILITIES 2006

Air Emission Plant

- Air Pollution Control Device
- Combustion Unit
- Fuel Material Location
- General Administrative Location
- Incinerator - AEP
- Point of Air Emission
- Process

Beneficial Land Use

- Parcel

Brownfields

- Brownfields

Captive Hazardous Waste Operation

- Boiler Industrial Furnace
- Disposal Facility - CAHWO
- Hazardous Generator Captive
- Incinerator - CAHWO
- Recycling Facility - CAHWO
- Storage Facility - CAHWO
- Treatment Facility - CAHWO

Coal Mining Operation

- Discharge Point - CMO
- Mineral Preparation Plant - CMO
- Post Mining Treatment
- Refuse Disposal Facility
- Refuse Reprocessing
- Surface Mine - CMO
- Underground Mine

Coal Pillar Location

- Coal Pillar - Mining
- Coal Pillar - Oil & Gas

Commercial Hazardous Waste Operation

- Disposal Facility - COHWO
- Hazardous Generator Commercial
- Recycling Facility - COHWO
- Storage Facility - COHWO
- Treatment Facility - COHWO

Encroachment Location

- Boat Launch Ramp
- Bridge - ENCL
- Bulkhead or Groin
- Ch 106 Floodplain Permit
- Channel Work
- Culvert - ENCL
- Dock
- Dredging
- Fill Stream Channel
- Flood Levee or Walls
- Floodway Activity
- Ford Crossing
- Gravel Bar Removal
- Intake Structure
- Non-Jurisdictional Dam - ENCL
- Other Activities
- Outfall Structure - ENCL
- PA Wetland Replacement Project

Pipeline or Conduit
Stream Bank Protection
Stream Enclosure
Stream Relocation
Stream Restoration
Stream Restoration w/ Dam Removal
Submerged Lands License Agreement
Temporary Wetland Impact
Treatment Wetland System
Wetland Impact
Wetland Mitigation Bank
Wetland Restoration

Encroachment Location for O&G

Bridge - OGEL
Culvert - OGEL

EPA Toxic Release Inventory

EPA Toxic Release Inventory

Erosion & Sediment Control Facility

Agricultural Activities
Commercial or Ind Dev
Government Facilities
Oil And Gas Development
Private Road or Residence
Public Road Construction
Recreational Facilities
Remediation/Restoration
Residential Subdivision
Sewerage or Water Systems
Silviculture
Utility Fac and/or Trans Lines

Industrial Mineral Mining Operation

Discharge Point - IMMO
Mineral Preparation Plant - IMMO
Surface Mine - IMMO
Underground Mine - IMMO

Land Recycling Cleanup Location

Air Media
Contained Release or Abandoned Container
Groundwater Media
Sediment Media
Soil Media
Surface Water Media
Waste Media

Mine Drainage Trmt/Land Recl Proj Loc

Coal Refuse Pile Reclamation
Deep Mine Reclamation
Internal Monitoring Point
Mine Drainage Treatment
Oil & Gas Well Reclamation
Surface Mine Reclamation

Municipal Waste Operation

Composting
Land Application - MWO
Landfill - Abandoned
Landfill - MWO
Processing Facility - MWO
Resource Recovery

Transfer Station - MWO

Oil & Gas Location

Land Application - OGL

Oil and Gas Well

Pit

Oil and Gas Water Pollution Control Facility

Discharge Point - OGWPC

Internal Monitoring Point - OGWPC

Treatment OGWPC

Radiation Facility

Accelerator

Mammography Quality Stds Act Tube

XRay Machine

Residual Waste Operation

Generator

Impoundment

Incinerator - RWO

Land Application - RWO

Landfill - RWO

Processing Facility - RWO

Transfer Station - RWO

Storage Tank Location

Storage Tank

Water Pollution Control Facility

Compost/Processing

Conveyance System

Discharge Point - WPCF

Groundwater Monitoring Point

Internal Monitoring Point - WPCF

Land Discharge

Outfall Structure - WPCF

Pump Station - WPCF

Storage Unit

Treatment Plant - WPCF

Water Resource

Discharge

Ground Water Withdrawal

Interconnection

Storage

Surface Water Withdrawal

Water Allocation

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

January 24, 2007
BVLR-ENV-07-001

Mr. Ronald A. Schwartz, P.E.
Assistant Regional Director
Southwest Region
Pennsylvania Department of Environmental Protection
400 Waterfront Drive
Pittsburgh, PA 15222-4745

Beaver Valley Power Station License Renewal Project Environmental Report

Dear Mr. Schwartz,

Thank you for your review and response to our recent letter regarding our renewed efforts to develop the Environmental Report for our License Renewal project. We appreciate the comments you included in your letter to ensure that any new or expanded activities or construction related to our project, follow the established permitting processes. We further thank you for providing the attachment, and your website link, identifying known environmental features near our location that may be of interest to us.

As we work to successfully completing our project, please contact me at 724-682-7139 or Mr. Michael Banko at 724-682-4117 with any questions.

Sincerely,

Clifford I. Custer
Project Manager

cc: M. D. Banko

Central File: *Keyword(s)- DEP Southwest Region*

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

December 4, 2006
BVLR-ENV-06-020

Mr. Douglas J. Austen, Executive Director
Pennsylvania Fish and Boat Commission
1601 Elmerton Avenue
P. O. Box 67000
Harrisburg, PA 17106-7000

Subject: Environmental Review for Beaver Valley Power Station License Renewal Project

Dear Mr. Austen:

In 2002, FirstEnergy Nuclear Operating Company (FENOC) requested your input to the Beaver Valley Power Station (BVPS) license renewal environmental review. FENOC is currently preparing a final application for submittal to the U.S. Nuclear Regulatory Commission (NRC). Upon successful acceptance by the NRC, the operating licenses for the two nuclear power generating units at BVPS, located in Beaver County, Pennsylvania will be renewed. You are likely aware that the operating licenses for many U.S. nuclear power plants have been recently renewed and that applications for license renewal of numerous other plants have been submitted to the NRC and are undergoing review. Upon issuance of the renewed operating licenses the life of the BVPS units will be extended for an additional 20 years (i.e., until 2036 and 2047 for Units 1 and 2, respectively).

In addition to detailed safety reviews, the license renewal process involves a thorough review of potential environmental impacts in accordance with provisions of the National Environmental Policy Act (NEPA). The attached fact sheet provides an overview of the process and associated environmental review activities to be conducted by FENOC and the NRC for the BVPS License Renewal. In brief, the NRC has prepared a generic environmental impact statement (GEIS) that addresses environmental impacts of license renewal on the basis of a review of plants nationwide. Detailed environmental reviews of individual plants, such as BVPS, include preparation of an environmental report (ER) by the applicant and a site-specific supplement to the GEIS by the NRC. The latter documents must include impact assessments for site-specific environmental issues that were not resolved generically by the NRC in the GEIS. They also must identify any known "new and significant information," i.e., new and significant environmental issues or impacts not recognized as such by the NRC in the GEIS, and the NRC's codified findings from the GEIS (10 CFR 51.53). In accordance with NEPA, the NRC's process for developing the site-specific supplements includes substantial opportunity for participation by agencies and the public, including the opportunity to formally comment on the scope of the NRC's site-specific supplement to the GEIS and the adequacy of that document.

Page Two
November 20, 2006

During the August 2002 through December 2004 period, agencies and stakeholders – including your group – did not identify any new and significant information or environmental impacts beyond those identified by the NRC. Nonetheless, the BVPS License Renewal Environmental Review Team would appreciate your early and active participation in the license renewal environmental review process for BVPS. In particular, we would welcome any new questions or concerns your agency may have developed regarding the environmental implications of BVPS license renewal, as well as any information that your agency may consider to be potentially "new and significant." These efforts will help ensure that the ER we prepare is complete and up-to-date. In this regard, if you believe it necessary, we would be pleased to meet with your agency representative(s) to discuss the BVPS license renewal environmental review in detail.

Please feel free to contact Mr. Clifford Custer, License Renewal Project Manager at 724-682-7139, or for environmental-specific issues, Mr. Michael Banko at 724-682-4117. Please address your agency's interest in a meeting, and any questions or concerns about the environmental review to:

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BVPS License Renewal Project Manager
Beaver Valley Power Station (Mail Stop BV-SIM2)
P.O. Box 4
Route 168 W
Shippingport, PA 15077-0004

Tel.: 724-682-7139
Email: custerc@firstenergycorp.com

Thank you on behalf of FENOC and the BVPS License Renewal Environmental Review Team.

Sincerely,

James H. Lash
Site Vice-President

Attachment

cc: C. I. Custer
G. A. Dunn
M. D. Banko
BVRC: *Keyword(s) – License Renewal Environmental Report*

ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

Background

FirstEnergy Corporation owns the Beaver Valley Power Station (BVPS); a two-unit nuclear power plant located on a 453-acre site on the Ohio River in Shippingport Borough, Beaver County, Pennsylvania. Upon completion of our full potential project, the capacity will approximate 924 MWe at Unit 1, 2 918 MWe at Unit 2, for a total of 1842 MWe for the site. BVPS features a close-cycle cooling system that uses two natural draft cooling towers. The Ohio River (New Cumberland Pool) provides the source of cooling tower makeup water and receives the cooling tower blowdown discharge. Transmission lines from BVPS consist of six 345-kV lines, two of which (BV-Sammis and BV-Hanna) extend into West Virginia and/or Ohio, and seven 138-kV lines, all in Pennsylvania.

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The License Renewal Environmental Review Process

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1

ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

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a. the impacts associated with the issue apply either to all plants or to plants having a specific cooling system or other specified plant or site characteristic;

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To ensure thorough analysis of all potential environmental impacts associated with license renewal, the NRC requires that applicants identify in the ER any "new and significant information" regarding the environmental impact of license renewal of which the applicant is aware. Such information includes potentially significant environmental issues the NRC did not consider in the GEIS and information that may lead to a different conclusion than was documented in the GEIS and codified in Table B-1 of the NRC regulations as cited above. In the course of developing the ER, applicants for a renewed operating license routinely consult with resource agencies. These consultations are undertaken to familiarize the agencies with the project, identify agency concerns, and obtain pertinent resource information, including any new and potentially significant information, as needed to ensure a complete and accurate application.

The NRC addresses any new and significant and site-specific issues, that are not resolved in the GEIS, in a Supplemental Environmental Impact Statement (SEIS). In preparing the SEIS, the NRC will use information submitted by FE and:

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5. Prepares the Final SEIS on the basis of comments received.

The ER will address applicable site-specific environmental issues related to extended operation of BVPS and other appropriate topics as specified in 10 CFR 51.53(c), including:

2

ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

- Applicable Category 2 issues, including potential impact on water use.
- Ecological resources, land use, and socio-economics.
- Environmental justice.
- New and significant issues, if applicable.
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- Historical and archaeological considerations

The NRC will establish a schedule for SEIS preparation and related activities once the application for BVPS has been submitted.

Environmental Review Activities For BVPS

FirstEnergy has conducted data gathering efforts as part of the ER development effort. Beginning in July 2002, FirstEnergy met with interested environmental resource agencies to familiarize them with the NRC license renewal process and the BVPS license renewal project, to obtain input. As previously mentioned and as a matter of statutory obligation or policy, the NRC is expected to request informal consultations with some agencies at the SEIS stage (e.g., U.S. Fish and Wildlife Service, PA Historic Preservation Office, PA Fish and Boat Commission, PA Game Commission, PA Department of Conservation & Natural Resources, PA Department of Health, Ohio Department of Natural Resources, West Virginia Division of Natural Resources). FirstEnergy specifically requested and received written input from these to include in the ER and facilitate these later consultations with the NRC.

Based on this and other communications, FE will follow up with them if requested.

We also understand that previous reviews for threatened or endangered species may not reflect current conditions. Therefore, in response to previous communications with the responsible agencies, since 2002, FirstEnergy has and will continue to conduct an annual review, through the Pennsylvania Natural Diversity Index (PNDI), in accordance with current Pennsylvania procedures.

Docketed Examples Available for Review

Various docketed GEIS and SEISs associated with nuclear plants requesting renewed operating licenses are available from the NRC as NUREG 1437 and associated supplements located at http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff. NRC regulations are readily available at http://www.nrc.gov/reading-rm/doc-collections/cfr/.

3

PENNSYLVANIA FISH & BOAT COMMISSION

established 1866

Pennsylvania Fish & Boat Commission

Division of Environmental Services
Natural Diversity Section
450 Robinson Lane
Bellefonte, PA 16823-9620
(814) 359-5237 Fax: (814) 359-5175

March 2, 2007

IN REPLY REFER TO
SIR# 24822

JULIE FIRESTONE
FENOC
BEAVER VALLEY POWER STATION
ROUTE 168, PO BOX 4
SHIPPINGPORT, PA 15077-0004

RE: **Species Impact Review (SIR) – Rare, Candidate, Threatened and Endangered Species**
PNDI Search No. 20070125074250
BEAVER VALLEY POWER STATION
GREENE, SHIPPINGPORT Township, BEAVER County, Pennsylvania

Dear Ms. FIRESTONE:

I have reviewed the map accompanying your recent correspondence, which concerns the above referenced project. Based on records maintained in the Pennsylvania Natural Diversity Inventory (PNDI) database and our own files, **rare or protected fish species are known from the vicinity of the proposed project site.**

Given the status and sensitivity of the species of concern, we will need more information to allow for a more thorough evaluation of potential adverse impacts from the proposed project. Items **such as** detailed site plans and map, aerial maps of the general area, project alternatives, stream characterizations (stream width, depth, velocity, bottom type, aquatic vegetation present, pH, specific conductance), wetlands/waterways and acreage to be impacted, general habitat descriptions and onsite color photographs (keyed to a site map) would expedite our review process. Pending the review of this information a survey for the species of concern may be warranted.

If you have any questions regarding this response, please contact Nevin Welte at 814-359-5234, **and refer to the SIR number** at the top of this letter. Thank you for your cooperation and attention to this matter of endangered species conservation and habitat protection.

Sincerely,

Christopher A. Urban

Christopher A. Urban, Chief
Natural Diversity Section

CAU/NW/ma
cc: DEP, SW Region

Our Mission: www.fish.state.pa.us

To provide fishing and boating opportunities through the protection and management of aquatic resources.

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

December 4, 2006
BVLR-ENV-06-025

Mr. James R. Leigey
Wildlife Impact Review Coordinator
Pennsylvania Game Commission
Section Oil, Gas & Mineral Dept.
2001 Elmerton Avenue
Harrisburg, PA 17110-9797

Subject: Environmental Review for Beaver Valley Power Station License Renewal Project

Dear Mr. Leigey:

In 2002, FirstEnergy Nuclear Operating Company (FENOC) requested your input to the Beaver Valley Power Station (BVPS) license renewal environmental review. FENOC is currently preparing a final application for submittal to the U.S. Nuclear Regulatory Commission (NRC). Upon successful acceptance by the NRC, the operating licenses for the two nuclear power generating units at BVPS, located in Beaver County, Pennsylvania will be renewed. You are likely aware that the operating licenses for many U.S. nuclear power plants have been recently renewed and that applications for license renewal of numerous other plants have been submitted to the NRC and are undergoing review. Upon issuance of the renewed operating licenses the life of the BVPS units will be extended for an additional 20 years (i.e., until 2036 and 2047 for Units 1 and 2, respectively).

In addition to detailed safety reviews, the license renewal process involves a thorough review of potential environmental impacts in accordance with provisions of the National Environmental Policy Act (NEPA). The attached fact sheet provides an overview of the process and associated environmental review activities to be conducted by FENOC and the NRC for the BVPS License Renewal. In brief, the NRC has prepared a generic environmental impact statement (GEIS) that addresses environmental impacts of license renewal on the basis of a review of plants nationwide. Detailed environmental reviews of individual plants, such as BVPS, include preparation of an environmental report (ER) by the applicant and a site-specific supplement to the GEIS by the NRC. The latter documents must include impact assessments for site-specific environmental issues that were not resolved generically by the NRC in the GEIS. They also must identify any known "new and significant information," i.e., new and significant environmental issues or impacts not recognized as such by the NRC in the GEIS, and the NRC's codified findings from the GEIS (10 CFR 51.53). In accordance with NEPA, the NRC's process for developing the site-specific supplements includes substantial opportunity for participation by agencies and the public, including the opportunity to formally comment on the scope of the NRC's site-specific supplement to the GEIS and the adequacy of that document.

Page Two
November 20, 2006

During the August 2002 through December 2004 period, agencies and stakeholders – including your group – did not identify any new and significant information or environmental impacts beyond those identified by the NRC. Nonetheless, the BVPS License Renewal Environmental Review Team would appreciate your early and active participation in the license renewal environmental review process for BVPS. In particular, we would welcome any new questions or concerns your agency may have developed regarding the environmental implications of BVPS license renewal, as well as any information that your agency may consider to be potentially "new and significant." These efforts will help ensure that the ER we prepare is complete and up-to-date. In this regard, if you believe it necessary, we would be pleased to meet with your agency representative(s) to discuss the BVPS license renewal environmental review in detail.

Please feel free to contact Mr. Clifford Custer, License Renewal Project Manager at 724-682-7139, or for environmental-specific issues, Mr. Michael Banko at 724-682-4117. Please address your agency's interest in a meeting, and any questions or concerns about the environmental review to:

Mr. Clifford I. Custer
BVPS License Renewal Project Manager
Beaver Valley Power Station (Mail Stop BV-SIM2)
P.O. Box 4
Route 168 W
Shippingport, PA 15077-0004

Tel.: 724-682-7139
Email: custerc@firstenergycorp.com

Thank you on behalf of FENOC and the BVPS License Renewal Environmental Review Team.

Sincerely,

James H. Lash
Site Vice-President

Attachment

cc: C. I. Custer
G. A. Dunn
M. D. Banko
BVRC: ***Keyword(s) – License Renewal Environmental Report***

ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

Background

FirstEnergy Corporation owns the Beaver Valley Power Station (BVPS); a two-unit nuclear power plant located on a 453-acre site on the Ohio River in Shippingport Borough, Beaver County, Pennsylvania. Upon completion of our full potential project, the capacity will approximate 924 MWe at Unit 1, 2 918 MWe at Unit 2, for a total of 1842 MWe for the site. BVPS features a close-cycle cooling system that uses two natural draft cooling towers. The Ohio River (New Cumberland Pool) provides the source of cooling tower makeup water and receives the cooling tower blowdown discharge. Transmission lines from BVPS consist of six 345-kV lines, two of which (BV-Sammis and BV-Hanna) extend into West Virginia and/or Ohio, and seven 138-kV lines, all in Pennsylvania.

The initial 40-year operating licenses for BVPS Units 1 and 2 expire in 2016 and 2027, respectively. In keeping with continued efforts to ensure a safe, reliable, and economical supply of energy to its customers, in August 2007 FirstEnergy plans to submit an application to the U.S. Nuclear Regulatory Commission (NRC) for a renewed license. The renewed license would authorize operation of the units for 20 years beyond their current license expiration dates; i.e., until 2036 and 2047, respectively.

The NRC license renewal application process involves a thorough technical evaluation of plant systems, structures, and components to assess the effects of aging, as well as development of measures to manage these effects to ensure continued safe operation through the period of extended operation. In accordance with the National Environmental Policy Act (NEPA), the license renewal process also involves an assessment of potential environmental impacts associated with extended operation of the plant; major plant refurbishments, if any, within the scope of license renewal; and associated transmission lines considered within the scope of license renewal.

The NRC's NEPA evaluation process provides substantial opportunities for input from stakeholders, including federal, state, and local agencies responsible for resources potentially affected by extended operation and associated major refurbishments. FirstEnergy previously met with interested agencies regarding potential environmental impacts related to extended operation, and is willing to do so again. Additionally, the NRC is specifically obligated to consult with the U.S. Fish and Wildlife Service and the State Historic Preservation Officers of Pennsylvania and other potentially affected states regarding potential impacts to threatened or endangered species and cultural resources, respectively.

FirstEnergy prepared this overview of the license renewal environmental review process to familiarize agency representatives with this process and facilitate active agency participation. Detailed information is available from the NRC license renewal website (http://www.nrc.gov/reactors/operating/licensing/renewal.html).

The License Renewal Environmental Review Process

The NRC requires applications for renewal of nuclear power plant operating licenses to include an environmental report (ER) which addresses the potential environmental impacts of license renewal and the alternatives to license renewal. To improve efficiency of the environmental review process for these applications, the NRC has prepared and issued a generic environmental impact statement (GEIS), *Generic Environmental Impact Statement for the License Renewal of*

1

ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

Nuclear Power Plants (i.e., NUREG-1437) and amended its environmental protection regulations in 10 CFR 51, Subpart A. In the GEIS, the NRC identified and evaluated 92 issues, representing a full range of potential environmental impacts that could result from license renewal, including impacts from any necessary plant refurbishment activities and impacts from plant operation beyond the current 40-year operating license term. The NRC designated 69 of the issues as Category 1, based on the following criteria:

a. the impacts associated with the issue apply either to all plants or to plants having a specific cooling system or other specified plant or site characteristic;

b. a single significance level (i.e., small, medium, or large) has been assigned to the impacts; and

c. additional plant-specific mitigation measures were likely to not be sufficiently beneficial to warrant implementation.

Environmental impacts associated with these Category 1 issues were thus identified, analyzed, and resolved in the GEIS. However, twenty-one (21) of the 92 total issues did not meet one or more of the Category 1 criteria and, were deemed Category 2 issues. Because these Category 2 issues could not be generically resolved, the NRC requires that they be addressed on a site-specific basis in the applicant's ER [10 CFR 51.53(c) and associated Appendix B, Table B-11].

To ensure thorough analysis of all potential environmental impacts associated with license renewal, the NRC requires that applicants identify in the ER any "new and significant information" regarding the environmental impact of license renewal of which the applicant is aware. Such information includes potentially significant environmental issues the NRC did not consider in the GEIS and information that may lead to a different conclusion than was documented in the GEIS and codified in Table B-1 of the NRC regulations as cited above. In the course of developing the ER, applicants for a renewed operating license routinely consult with resource agencies. These consultations are undertaken to familiarize the agencies with the project, identify agency concerns, and obtain pertinent resource information, including any new and potentially significant information, as needed to ensure a complete and accurate application.

The NRC addresses any new and significant and site-specific issues, that are not resolved in the GEIS, in a Supplemental Environmental Impact Statement (SEIS). In preparing the SEIS, the NRC will use information submitted by FE and:

1. Solicits stakeholder input from media sources and at public meetings to finalize the SEIS scope.
2. Consults with resource agencies to determine agency concerns and obtain additional information.
3. Prepares a Draft SEIS on the basis of independent analysis, using input from the applicant, resource agencies, and the public.
4. Solicits stakeholder comments on the Draft SEIS in the media and at public meetings.
5. Prepares the Final SEIS on the basis of comments received.

The ER will address applicable site-specific environmental issues related to extended operation of BVPS and other appropriate topics as specified in 10 CFR 51.53(c), including:

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ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

- Applicable Category 2 issues, including potential impact on water use.
- Ecological resources, land use, and socio-economics.
- Environmental justice.
- New and significant issues, if applicable.
- Alternatives to license renewal (e.g., generation alternatives).
- Historical and archaeological considerations

The NRC will establish a schedule for SEIS preparation and related activities once the application for BVPS has been submitted.

Environmental Review Activities For BVPS

FirstEnergy has conducted data gathering efforts as part of the ER development effort. Beginning in July 2002, FirstEnergy met with interested environmental resource agencies to familiarize them with the NRC license renewal process and the BVPS license renewal project, to obtain input. As previously mentioned and as a matter of statutory obligation or policy, the NRC is expected to request informal consultations with some agencies at the SEIS stage (e.g., U.S. Fish and Wildlife Service, PA Historic Preservation Office, PA Fish and Boat Commission, PA Game Commission, PA Department of Conservation & Natural Resources, PA Department of Health, Ohio Department of Natural Resources, West Virginia Division of Natural Resources). FirstEnergy specifically requested and received written input from these to include in the ER and facilitate these later consultations with the NRC.

Based on this and other communications, FE will follow up with them if requested.

We also understand that previous reviews for threatened or endangered species may not reflect current conditions. Therefore, in response to previous communications with the responsible agencies, since 2002, FirstEnergy has and will continue to conduct an annual review, through the Pennsylvania Natural Diversity Index (PNDI), in accordance with current Pennsylvania procedures.

Docketed Examples Available for Review

Various docketed GEIS and SEISs associated with nuclear plants requesting renewed operating licenses are available from the NRC as NUREG 1437 and associated supplements located at http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff. NRC regulations are readily available at http://www.nrc.gov/reading-rm/doc-collections/cfr/.

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COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA GAME COMMISSION
2001 ELMERTON AVENUE, HARRISBURG, PA 17110-9797

January 8, 2007

Mr. Clifford I. Custer
BVPS License Renewal Project Manager
Beaver Valley Power Station (Mail Stop BV-SIM2)
PO Box 4
Route 168W
Shippingport, PA 15077-0004

In re: PNDI Review Request
Beaver Valley Power Station License Renewal Project
Shippensport Borough
Beaver County, PA

Dear Mr. Custer:

This is in response to your letter of December 4, 2006 regarding the potential impacts of your proposed project(s) on special concern species of birds or mammals.

Our office review has determined that your proposed project(s) should not cause any adverse impacts to any special concern species of birds or mammals. This determination may be reconsidered if project plans change or extend beyond the present study area, or if additional information becomes available on state-listed species.

If you have any questions, please contact me at (717) 783-5957. Please be advised that this determination is only valid for one year from the date of this letter.

Very truly yours,

James R. Leigey
Wildlife Impact Review Coordinator
Division of Environmental
Planning and Habitat Protection
Bureau of Wildlife Habitat Management

Cc: File

ADMINISTRATIVE BUREAUS:
PERSONNEL: 717-787-7836 ADMINISTRATION: 717-787-5670 AUTOMOTIVE AND PROCUREMENT DIVISION: 717-787-6594
LICENSE DIVISION: 717-787-2084 WILDLIFE MANAGEMENT: 717-787-5529. INFORMATION & EDUCATION: 717-787-6286 LAW ENFORCEMENT: 717-787-5740
LAND MANAGEMENT: 717-787-6818 REAL ESTATE DIVISION: 717-787-6568 AUTOMATED TECHNOLOGY SYSTEMS: 717-787-4076 FAX: 717-772-2411
WWW.PGC.STATE.PA.US
AN EQUAL OPPORTUNITY EMPLOYER

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

December 4, 2006
BVLR-ENV-06-067

Ms. Carolyn Kender, Archaeologist
The Cultural Center, Capitol Complex
West Virginia Division of Culture & History
1900 Kanawha Boulevard, East
Charleston, WV 25305-0360

Subject: Environmental Review for Beaver Valley Power Station License Renewal Project

Dear Ms. Kender:

In 2002, FirstEnergy Nuclear Operating Company (FENOC) requested your input to the Beaver Valley Power Station (BVPS) license renewal environmental review. FENOC is currently preparing a final application for submittal to the U.S. Nuclear Regulatory Commission (NRC). Upon successful acceptance by the NRC, the operating licenses for the two nuclear power generating units at BVPS, located in Beaver County, Pennsylvania will be renewed. You are likely aware that the operating licenses for many U.S. nuclear power plants have been recently renewed and that applications for license renewal of numerous other plants have been submitted to the NRC and are undergoing review. Upon issuance of the renewed operating licenses the life of the BVPS units will be extended for an additional 20 years (i.e., until 2036 and 2047 for Units 1 and 2, respectively).

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Page Two
November 20, 2006

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Mr. Clifford I. Custer
BVPS License Renewal Project Manager
Beaver Valley Power Station (Mail Stop BV-SIM2)
P.O. Box 4
Route 168 W
Shippingport, PA 15077-0004

Tel.: 724-682-7139
Email: custerc@firstenergycorp.com

Thank you on behalf of FENOC and the BVPS License Renewal Environmental Review Team.

Sincerely,

James H. Lash
Site Vice-President

Attachment

cc: C. I. Custer
G. A. Dunn
M. D. Banko
BVRC: ***Keyword(s) – License Renewal Environmental Report***

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For The Beaver Valley Power Station

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ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

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ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

- Applicable Category 2 issues, including potential impact on water use.
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- Environmental justice.
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Environmental Review Activities For BVPS

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We also understand that previous reviews for threatened or endangered species may not reflect current conditions. Therefore, in response to previous communications with the responsible agencies, since 2002, FirstEnergy has and will continue to conduct an annual review, through the Pennsylvania Natural Diversity Index (PNDI), in accordance with current Pennsylvania procedures.

Docketed Examples Available for Review

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WEST VIRGINIA
DIVISION OF
CULTURE & HISTORY
The Cultural Center
1900 Kanawha Blvd., E.
Charleston, WV
25305-0300
Phone 304.558.0220
Fax 304.558.2779
TDD 304.558.3562
www.wvculture.org
EEO/AA Employer

January 9, 2006

Mr. Clifford I. Custer
Project Manager
Beaver Valley Power Station
Route 168 W
PO Box 4
Shippingport, PA 15077

Re: Beaver Valley Power Station
Environmental Review for License Renewal
FR#: 07-206-HK

Dear Mr. Custer:

We have reviewed the above mentioned project to determine its effects to cultural resources. As required by Section 106 of the National Historic Preservation Act, as amended, and its implementing regulations, 36 CFR 800: "Protection of Historic Properties," we submit our comments.

It is our understanding that Beaver Valley Power Station (BVPS) is conducting an environmental review for license renewal. Upon issuance of the renewed license, the life of BVPS Units 1 and 2 will be extended for an additional 20 years, until 2036 and 2047, respectively. Per your request, we are providing comments regarding the potential of the extended license to effect historic resources within West Virginia.

Archaeological Resources:
It is our understanding that two existing BVPS transmission lines extend into Hancock County, West Virginia and that no new ground disturbing activities are planned as part of the license renewal process. It is our opinion, therefore, that this project will have no effect on any archaeological resources that are eligible for or listed in the National Register of Historic Places. Should future ground disturbing activities be planned by BVPS in West Virginia, you will need to initiate the Section 106.

Architectural Resources:
The West Virginia State Historic Preservation Office has reviewed the information provided with the request for Environmental Review. Unfortunately, we can not complete our review with the information provided. Please indicate the location of the two nuclear power generating units located in Beaver County, Pennsylvania and the height of the units so we may determine the view shed to Hancock County, West Virginia. Also, please

Mr. Custer
January 9, 2007
Page 2

indicate on a USGS map the location of the transmission lines from BVPS that extend into West Virginia. We will complete our review upon receipt of the materials requested.

We appreciate the opportunity to be of service. *If you have any questions regarding our comments or the Section 106 process, please call Lora Lamarre, Senior Archaeologist, or Ginger Williford, Structural Historian, at (304) 558-0240.*

Sincerely,

Susan M. Pierce

Susan M. Pierce
Deputy State Historic Preservation Officer

SMP/LAL/GW

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

February 20, 2007
BVLR-ER-07-002

Ms. Susan M. Pierce
Deputy State Historic Preservation Officer
West Virginia Division of Culture & History
The Cultural Center
1900 Kanawha Blvd. E.
Charleston, WV 25305-0300

Re: Request for More Information Regarding Beaver Valley Power Station License Renewal Environmental Review (FR#: 07-206-HK)

Dear Ms. Pierce,

Thank you for your review and response to date. In your letter to us date January 9, 2007 (FR#: 07-206-HK), you requested additional information regarding the location of Beaver Valley Power Station (BVPS), its height, and the location of associated transmission lines through Hancock County, WV. We are pleased to provide that information to you.

Location of BVPS:

The facility is located on the south bank of the Ohio River. On the United States Geological Survey (USGS) maps, it is on the very northernmost edge of the Hookstown, PA quadrangle, and on the very southernmost edge of the Midland, PA quadrangle. Data for the approximate center of the facility are:

- Latitude/Longitude: 40°27'33" / 80°25'57"
- Ohio River mile 34.5

Please see the attached combined USGS maps that show the location of BVPS relative to the Ohio River, as well as to the West Virginia, Ohio, and Pennsylvania state lines.

Height of BVPS

The tallest structures at the facility are the two parabolic cooling towers. Each is approximately 550' high. Adding that value to the nominal general site elevation of 735' above sea level, the approximated height above sea level for the cooling towers is not more than 1,285'. Looking at the USGS topographical maps, there are several peaks between BVPS and the West Virginia state line that are over 1,100' high and thus, would make view of the cooling towers unlikely from that state.

Please see the attached combined USGS maps that show the location of BVPS relative to the Ohio River, as well as to the West Virginia, Ohio, and Pennsylvania state lines.

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

Location of Transmission Lines through Hancock County, WV

A transmission line designated as BV-Sammis traverses through Hancock County, WV between the PA state line, and the Ohio state line at the Ohio River. Please see the attached combined USGS maps that show the path of the BV-Sammis transmission lines.

Should you or your staff need more information or have any questions, please direct them to Mr. Michael Banko, at 724-682-4117.

Sincerely,

Clifford I. Custer
License Renewal Project Manager

Attachment

cc: M. D. Banko
C. A. Munoz (A-GO-10)
B. F. Sepelak (A-BV-A)

Central File: ***Keyword(s)- License Renewal ER***

WEST VIRGINIA
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TDD 304.558.3562
www.wvculture.org
EEO/AA Employer

March 14, 2006

Mr. Clifford I. Custer
Project Manager
Beaver Valley Power Station
Route 168 W
PO Box 4
Shippingport, PA 15077

Re: Beaver Valley Power Station
Environmental Review for License Renewal
FR#: 07-206-HK-1

Dear Mr. Custer:

We have reviewed the additional information for the above mentioned project to determine its effects to cultural resources. As required by Section 106 of the National Historic Preservation Act, as amended, and its implementing regulations, 36 CFR 800: "Protection of Historic Properties," we submit our comments.

It is our understanding that Beaver Valley Power Station (BVPS) is conducting an environmental review for license renewal. Upon issuance of the renewed license, the life of BVPS Units 1 and 2 will be extended for an additional 20 years, until 2036 and 2047, respectively. Per your request, we are providing comments regarding the potential of the extended license to effect historic resources within West Virginia.

Architectural Resources:
Thank you for the additional information requested in our letter dated January 9, 2006. We concur that the two parabolic cooling towers are unlikely to be seen from West Virginia. It is our opinion there are no cultural resources within the project area that are eligible for or listed in the National Register of Historic Places. No further consultation is necessary with respect to cultural resources.

We appreciate the opportunity to be of service. *If you have any questions regarding our comments or the Section 106 process, please call Ginger Williford, Structural Historian, at (304) 558-0240.*

Sincerely,

Susan M. Pierce

Susan M. Pierce
Deputy State Historic Preservation Officer

SMP/GW

FENOC
FirstEnergy Nuclear Operating Company

Beaver Valley Power Station
Route 168
P.O. Box 4
Shippingport, PA 15077-0004

December 4, 2006
BVLR-ENV-06-047

Dr. Samuel W. Speek, Director
Ohio Department of Natural Resources
2045 Morse Road
Columbus, OH 43229

Subject: Environmental Review for Beaver Valley Power Station License Renewal Project

Dear Dr. Speek:

In 2002, FirstEnergy Nuclear Operating Company (FENOC) requested your input to the Beaver Valley Power Station (BVPS) license renewal environmental review. FENOC is currently preparing a final application for submittal to the U.S. Nuclear Regulatory Commission (NRC). Upon successful acceptance by the NRC, the operating licenses for the two nuclear power generating units at BVPS, located in Beaver County, Pennsylvania will be renewed. You are likely aware that the operating licenses for many U.S. nuclear power plants have been recently renewed and that applications for license renewal of numerous other plants have been submitted to the NRC and are undergoing review. Upon issuance of the renewed operating licenses the life of the BVPS units will be extended for an additional 20 years (i.e., until 2036 and 2047 for Units 1 and 2, respectively).

In addition to detailed safety reviews, the license renewal process involves a thorough review of potential environmental impacts in accordance with provisions of the National Environmental Policy Act (NEPA). The attached fact sheet provides an overview of the process and associated environmental review activities to be conducted by FENOC and the NRC for the BVPS License Renewal. In brief, the NRC has prepared a generic environmental impact statement (GEIS) that addresses environmental impacts of license renewal on the basis of a review of plants nationwide. Detailed environmental reviews of individual plants, such as BVPS, include preparation of an environmental report (ER) by the applicant and a site-specific supplement to the GEIS by the NRC. The latter documents must include impact assessments for site-specific environmental issues that were not resolved generically by the NRC in the GEIS. They also must identify any known "new and significant information," i.e., new and significant environmental issues or impacts not recognized as such by the NRC in the GEIS, and the NRC's codified findings from the GEIS (10 CFR 51.53). In accordance with NEPA, the NRC's process for developing the site-specific supplements includes substantial opportunity for participation by agencies and the public, including the opportunity to formally comment on the scope of the NRC's site-specific supplement to the GEIS and the adequacy of that document.

Page Two
November 20, 2006

During the August 2002 through December 2004 period, agencies and stakeholders – including your group – did not identify any new and significant information or environmental impacts beyond those identified by the NRC. Nonetheless, the BVPS License Renewal Environmental Review Team would appreciate your early and active participation in the license renewal environmental review process for BVPS. In particular, we would welcome any new questions or concerns your agency may have developed regarding the environmental implications of BVPS license renewal, as well as any information that your agency may consider to be potentially "new and significant." These efforts will help ensure that the ER we prepare is complete and up-to-date. In this regard, if you believe it necessary, we would be pleased to meet with your agency representative(s) to discuss the BVPS license renewal environmental review in detail.

Please feel free to contact Mr. Clifford Custer, License Renewal Project Manager at 724-682-7139, or for environmental-specific issues, Mr. Michael Banko at 724-682-4117. Please address your agency's interest in a meeting, and any questions or concerns about the environmental review to:

Mr. Clifford I. Custer
BVPS License Renewal Project Manager
Beaver Valley Power Station (Mail Stop BV-SIM2)
P.O. Box 4
Route 168 W
Shippingport, PA 15077-0004

Tel.: 724-682-7139
Email: custerc@firstenergycorp.com

Thank you on behalf of FENOC and the BVPS License Renewal Environmental Review Team.

Sincerely,

James H. Lash
Site Vice-President

Attachment

cc: C. I. Custer
G. A. Dunn
M. D. Banko
BVRC: ***Keyword(s) – License Renewal Environmental Report***

ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

Background

FirstEnergy Corporation owns the Beaver Valley Power Station (BVPS); a two-unit nuclear power plant located on a 453-acre site on the Ohio River in Shippingport Borough, Beaver County, Pennsylvania. Upon completion of our full potential project, the capacity will approximate 924 MWe at Unit 1, 2 918 MWe at Unit 2, for a total of 1842 MWe for the site. BVPS features a close-cycle cooling system that uses two natural draft cooling towers. The Ohio River (New Cumberland Pool) provides the source of cooling tower makeup water and receives the cooling tower blowdown discharge. Transmission lines from BVPS consist of six 345-kV lines, two of which (BV-Sammis and BV-Hanna) extend into West Virginia and/or Ohio, and seven 138-kV lines, all in Pennsylvania.

The initial 40-year operating licenses for BVPS Units 1 and 2 expire in 2016 and 2027, respectively. In keeping with continued efforts to ensure a safe, reliable, and economical supply of energy to its customers, in August 2007 FirstEnergy plans to submit an application to the U.S. Nuclear Regulatory Commission (NRC) for a renewed license. The renewed license would authorize operation of the units for 20 years beyond their current license expiration dates; i.e., until 2036 and 2047, respectively.

The NRC license renewal application process involves a thorough technical evaluation of plant systems, structures, and components to assess the effects of aging, as well as development of measures to manage these effects to ensure continued safe operation through the period of extended operation. In accordance with the National Environmental Policy Act (NEPA), the license renewal process also involves an assessment of potential environmental impacts associated with extended operation of the plant; major plant refurbishments, if any, within the scope of license renewal; and associated transmission lines considered within the scope of license renewal.

The NRC's NEPA evaluation process provides substantial opportunities for input from stakeholders, including federal, state, and local agencies responsible for resources potentially affected by extended operation and associated major refurbishments. FirstEnergy previously met with interested agencies regarding potential environmental impacts related to extended operation, and is willing to do so again. Additionally, the NRC is specifically obligated to consult with the U.S. Fish and Wildlife Service and the State Historic Preservation Officers of Pennsylvania and other potentially affected states regarding potential impacts to threatened or endangered species and cultural resources, respectively.

FirstEnergy prepared this overview of the license renewal environmental review process to familiarize agency representatives with this process and facilitate active agency participation. Detailed information is available from the NRC license renewal website (http://www.nrc.gov/reactors/operating/licensing/renewal.html).

The License Renewal Environmental Review Process

The NRC requires applications for renewal of nuclear power plant operating licenses to include an environmental report (ER) which addresses the potential environmental impacts of license renewal and the alternatives to license renewal. To improve efficiency of the environmental review process for these applications, the NRC has prepared and issued a generic environmental impact statement (GEIS), *Generic Environmental Impact Statement for the License Renewal of*

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ATTACHMENT:
License Renewal Environmental Review Process
For The Beaver Valley Power Station

Nuclear Power Plants (i.e., NUREG-1437) and amended its environmental protection regulations in 10 CFR 51, Subpart A. In the GEIS, the NRC identified and evaluated 92 issues, representing a full range of potential environmental impacts that could result from license renewal, including impacts from any necessary plant refurbishment activities and impacts from plant operation beyond the current 40-year operating license term. The NRC designated 69 of the issues as Category 1, based on the following criteria:

a. the impacts associated with the issue apply either to all plants or to plants having a specific cooling system or other specified plant or site characteristic;

b. a single significance level (i.e., small, medium, or large) has been assigned to the impacts; and

c. additional plant-specific mitigation measures were likely to not be sufficiently beneficial to warrant implementation.

Environmental impacts associated with these Category 1 issues were thus identified, analyzed, and resolved in the GEIS. However, twenty-one (21) of the 92 total issues did not meet one or more of the Category 1 criteria and, were deemed Category 2 issues. Because these Category 2 issues could not be generically resolved, the NRC requires that they be addressed on a site-specific basis in the applicant's ER [10 CFR 51.53(c) and associated Appendix B, Table B-11].

To ensure thorough analysis of all potential environmental impacts associated with license renewal, the NRC requires that applicants identify in the ER any "new and significant information" regarding the environmental impact of license renewal of which the applicant is aware. Such information includes potentially significant environmental issues the NRC did not consider in the GEIS and information that may lead to a different conclusion than was documented in the GEIS and codified in Table B-1 of the NRC regulations as cited above. In the course of developing the ER, applicants for a renewed operating license routinely consult with resource agencies. These consultations are undertaken to familiarize the agencies with the project, identify agency concerns, and obtain pertinent resource information, including any new and potentially significant information, as needed to ensure a complete and accurate application.

The NRC addresses any new and significant and site-specific issues, that are not resolved in the GEIS, in a Supplemental Environmental Impact Statement (SEIS). In preparing the SEIS, the NRC will use information submitted by FE and:

1. Solicits stakeholder input from media sources and at public meetings to finalize the SEIS scope.
2. Consults with resource agencies to determine agency concerns and obtain additional information.
3. Prepares a Draft SEIS on the basis of independent analysis, using input from the applicant, resource agencies, and the public.
4. Solicits stakeholder comments on the Draft SEIS in the media and at public meetings.
5. Prepares the Final SEIS on the basis of comments received.

The ER will address applicable site-specific environmental issues related to extended operation of BVPS and other appropriate topics as specified in 10 CFR 51.53(c), including:

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License Renewal Environmental Review Process
For The Beaver Valley Power Station

- Applicable Category 2 issues, including potential impact on water use.
- Ecological resources, land use, and socio-economics.
- Environmental justice.
- New and significant issues, if applicable.
- Alternatives to license renewal (e.g., generation alternatives).
- Historical and archaeological considerations

The NRC will establish a schedule for SEIS preparation and related activities once the application for BVPS has been submitted.

Environmental Review Activities For BVPS

FirstEnergy has conducted data gathering efforts as part of the ER development effort. Beginning in July 2002, FirstEnergy met with interested environmental resource agencies to familiarize them with the NRC license renewal process and the BVPS license renewal project, to obtain input. As previously mentioned and as a matter of statutory obligation or policy, the NRC is expected to request informal consultations with some agencies at the SEIS stage (e.g., U.S. Fish and Wildlife Service, PA Historic Preservation Office, PA Fish and Boat Commission, PA Game Commission, PA Department of Conservation & Natural Resources, PA Department of Health, Ohio Department of Natural Resources, West Virginia Division of Natural Resources). FirstEnergy specifically requested and received written input from these to include in the ER and facilitate these later consultations with the NRC.

Based on this and other communications, FE will follow up with them if requested.

We also understand that previous reviews for threatened or endangered species may not reflect current conditions. Therefore, in response to previous communications with the responsible agencies, since 2002, FirstEnergy has and will continue to conduct an annual review, through the Pennsylvania Natural Diversity Index (PNDI), in accordance with current Pennsylvania procedures.

Docketed Examples Available for Review

Various docketed GEIS and SEISs associated with nuclear plants requesting renewed operating licenses are available from the NRC as NUREG 1437 and associated supplements located at http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff. NRC regulations are readily available at http://www.nrc.gov/reading-rm/doc-collections/cfr/.

Clifford I Custer/FirstEnergy
12/29/2006 08:59 AM

To Lance R Garrett/FirstEnergy@FirstEnergy
cc Mike D Banko/FirstEnergy@FirstEnergy, Julie A Firestone/FirstEnergy@FirstEnergy, David F Kunsemiller/CONTRACTORS/FirstEnergy@FirstEnergy
bcc
Subject Fw: 06-0316; Beaver Valley Power Station

Lance please print and file this e-mail with our Environmental Report logbook.

Cliff Custer
FENOC Project Manager
License Renewal
Work: (724) 682-7139
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----- Forwarded by Clifford I Custer/FirstEnergy on 12/29/2006 08:57 AM -----

"Bankey, Mindy" <Mindy.Bankey@dnr.state.oh.us>
12/29/2006 07:57 AM

To <custerc@firstenergycorp.com>
cc
Subject 06-0316; Beaver Valley Power Station

ODNR COMMENTS TO Mr. Clifford I. Custer, BVPS License Renewal Project Manager, Beaver Valley Power Station, P.O. Box 4, Shippingport, Pennsylvania 15077-0004.

Location: The site is located along the Ohio River, Beaver County, Pennsylvania.
Project: First Energy Nuclear Operating Company is seeking comments on the Beaver Valley Power Station License Renewal. The new license would extend the life of the BVPS for an additional 20 years.

The Ohio Department of Natural Resources (ODNR) has completed a review of the above referenced project. These comments were generated by an inter-disciplinary review within the Department. These comments have been prepared under the authority of the Fish and Wildlife Coordination Act (48 Stat. 401, as amended; 16 U.S.C. 661 et seq.), the National Environmental Policy Act, the Coastal Zone Management Act, Ohio Revised Code and other applicable laws and regulations. These comments are also based on ODNR's experience as the state natural resource management agency and do not supersede or replace the regulatory authority of any local, state or federal agency nor relieve the applicant of the obligation to comply with any local, state or federal laws or regulations.

Rare and Endangered Species: The ODNR, Division of Natural Areas and Preserves, Natural Heritage Database contains no records of rare species or unique natural features within the proposed project, and there are no state nature preserves or scenic rivers in the vicinity of the site.

Fish and Wildlife: The ODNR, Division of Wildlife (DOW) has no comments regarding this project.

ODNR appreciates the opportunity to provide these comments. Please contact Mindy Bankey at 614.265.6836 if you have questions about these comments or need additional information.

Mindy Bankey
Environmental Administrator

Division of Real Estate & Land Management
Ohio Department of Natural Resources
2045 Morse Rd, C4
Columbus, Ohio 43229-6693
614.265.6836
Fax 614.267.4764

ATTACHMENT C SEVERE ACCIDENT MITIGATION ALTERNATIVES (SAMAS)

ATTACHMENT C-1 BEAVER VALLEY UNIT 1 SAMA ANALYSIS

EXECUTIVE SUMMARY

This report provides an analysis of the Severe Accident Mitigation Alternatives (SAMAs) that were identified for consideration by the Beaver Valley Power Station Unit 1. This analysis was conducted on a cost/benefit basis. The benefit results are contained in Section 4 of this report. Candidate SAMAs that do not have benefit evaluations have been eliminated from further consideration for any of the following reasons:

- The cost is considered excessive compared with benefits.
- The improvement is not applicable to Beaver Valley Unit 1.
- The improvement has already been implemented at Beaver Valley Unit 1 or the intent of the improvement is met for Beaver Valley Unit 1.

After eliminating a portion of the SAMAs for the preceding reasons, the remaining SAMAs are evaluated from a cost-benefit perspective. In general, the analysis approach examines the SAMAs from a bounding analysis approach to determine whether the expected cost would exceed a conservative approximation of the actual expected benefit. In most cases, therefore, a detailed risk evaluation in which a specific modification/procedure change is evaluated would indicate a smaller benefit than calculated in this evaluation.

Major insights from this benefit evaluation process included the following:

- If all core damage risk is eliminated, then the benefit in dollars over 20 years is $5,120,856.
- The largest contributors to the total benefit estimate are from offsite dose savings and offsite property costs.
- A large number of SAMAs had already been addressed by existing plant features, modifications to improve the plant, existing procedures, or procedure changes to enhance human performance.

BVPS Unit 1 Potentially Cost Beneficial SAMAs

BV1 SAMA Number	Potential Improvement	Discussion	Additional Discussion
164	Modify emergency procedures to isolate a faulted SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	
187	Increase seismic ruggedness of the ERF Substation batteries. This applies to the battery rack only and not the entire structure.	Increased reliability of the ERF diesel following seismic events	
189	Provide Diesel backed power for the fuel pool purification pumps and valves used for makeup to the RWST.	Increased availability of the RWST during loss of offsite power and station blackout events.	BVPS plans to implement this SAMA through alternate mitigation strategies that provide portable pumps that can be used for RWST makeup by the end of 2007.

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1 INTRODUCTION

1.1 PURPOSE

The purpose of the analysis is to identify SAMA candidates at the Beaver Valley Power Station Unit 1 that have the potential to reduce severe accident risk and to determine whether implementation of the individual SAMA candidate would be cost beneficial. NRC license renewal environmental regulations require SAMA evaluation.

1.2 REQUIREMENTS

- 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...."

2 METHOD

The SAMA analysis approach applied in the Beaver Valley assessment consists of the following steps.

- **Determine Severe Accident Risk**

    Level 1 and 2 Probabilistic Risk Assessment (PRA) Model
    The Beaver Valley Unit 1 PRA model (Section 3.1 – 3.2) was used as input to the consolidated Beaver Valley Unit 1/2 Level 3 PRA analysis (Section 3.4).

    The PRA results include the risk from internal and external events. The external hazards evaluated in the PRA are internal fires and seismic events only. High winds and tornadoes, external floods, and transportation and nearby facility accidents are not included in the results since they were screened from the IPEEE submittal because their individual CDF fell below the cutoff criteria of 1.0E-06 per year.

Level 3 PRA Analysis
The Level 1 and 2 PRA output and site-specific meteorology, demographic, land use, and emergency response data was used as input for the consolidated Beaver Valley Unit 1/2 Level 3 PRA (Section 3). This combined model was used to estimate the severe accident risk 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 to estimate the cost of severe accident risk were used throughout this analysis. In this step these techniques were used to estimate the maximum benefit that a SAMA could achieve if it eliminated all risk i.e., the maximum benefit (Section 4).

- **SAMA Identification**

In this step potential SAMA candidates (plant enhancements that reduce the likelihood of core damage and/or reduce releases from containment) were identified by Beaver Valley Unit 1 (BVPS-1) plant staff, from the PRA model, Individual Plant Examination (IPE) and IPE – External Events (IPEEE) recommendations, and industry documentation (Section 5). This process included consideration of the PRA importance analysis because it has been demonstrated by past SAMA analyses that 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.

- **Preliminary Screening (Phase I SAMA Analysis)**

Because many of the SAMA candidates identified in the previous step are from the industry, it was necessary to screen out SAMA candidates that were not applicable to the BVPS-1 design, candidates that had already been implemented or whose benefits have been achieved at the plant using other means, and candidates whose roughly estimated cost exceeded the maximum benefit. Additionally, PRA insights (specifically, importance measures) were used directly to screen SAMA candidates that did not address significant contributors to risk in this phase (Section 6).

- **Final Screening (Phase II SAMA Analysis)**

In this step of the analysis the benefit of severe accident risk reduction was estimated for each of the remaining SAMA candidates and compared to an implementation cost estimate to determine net cost-benefit (Section 7). The benefit associated with each SAMA was determined by the reduction in severe accident risk from the baseline derived by modifying the plant model to represent the plant after implementing the candidate. In general, the modeling approach used was a bounding approach to first determine a bounding value of the benefit. If this benefit was determined to be smaller that the expected cost, no further modeling detail was necessary. If the benefit was found to be greater that the estimated cost, the modeling was refined to remove conservatism in the modeling and a less conservative benefit was determined for comparison with the estimated cost.

Similarly, the initial cost estimate used in this analysis was the input from the expert panel (plant staff familiar with design, construction, operation, training and maintenance) meeting. All costs associated with a SAMA were considered, including design, engineering, safety analysis, installation, and long-term maintenance, calibrations, training, etc. If the estimated cost was found to be close to the estimated benefit, then first the benefit evaluation was refined to remove conservatism and if the estimated cost and benefit were still close, then the cost estimate was refined to assure that both the benefit calculation and the cost estimate are sufficiently accurate to justify further decision making based upon the estimates.

- **Sensitivity Analysis**

The next step in the SAMA analysis process involved evaluation on the impact of changes in SAMA analysis assumptions and uncertainties on the cost-benefit analysis (Section 8).

- **Identify Conclusions**

The final step involved summarizing the results and conclusions (Section 9).

3 SEVERE ACCIDENT RISK

The BVPS PRA models describe the results of the first two levels of the BVPS probabilistic risk assessment for the plant's two units. These levels are defined as follows: Level 1 determines CDFs based on system analyses and human reliability assessments; Level 2 evaluates the impact of severe accident phenomena on radiological releases and quantifies the condition of the containment and the characteristics of the release of fission products to the environment. The BVPS models use PRA techniques to:

- Develop an understanding of severe accident behavior;
- Understand the most likely severe accident consequences;
- Gain a quantitative understanding of the overall probabilities of core damage and fission product releases; and

- Evaluate hardware and procedure changes to assess the overall probabilities of core damage and fission product releases.

The Unit 1 and Unit 2 PRAs were initiated in response to Generic Letter 88-20, which resulted in IPE and IPE for External Events (IPEEE) analyses. The current model for each Unit (BV1REV4 for Unit 1 and BV2REV4 for Unit 2) is a consolidated Level 1 / Level 2 model including both internal and external initiating events (i.e., consolidates IPE and IPEEE studies into a single, Unit-specific PRA model) for power operation. This means that severe accident sequences have been developed from internal and external initiated events, including internal floods, internal fires, and seismic events.

The PRA models used in this analysis to calculate severe accident risk due to Unit 1 are described in this section. The Unit 1 Level 1 PRA model (internal and external), the Unit 1 Level 2 PRA model, Unit 1 PRA model review history, and the Unit 1 Level 3 PRA model, are described in Section 3.1, 3.2 and 3.4.

3.1 LEVEL 1 PRA MODEL

3.1.1 Internal Events

3.1.1.1 Description of Level 1 Internal Events PRA Model

The US Nuclear Regulatory Commission (NRC) issued Generic Letter No. 88-20, in December 1988, which requested each plant to perform an individual plant examination of internal events (IPE) to identify any vulnerabilities. In response, Duquesne Light Company (DLC) submitted an IPE report (Reference 2) using a probabilistic risk assessment (PRA) approach for Beaver Valley Power Station Unit 1 (BVPS-1) in October 1992 that examined risk from internal events, including internal flooding.

The updated PRA model, used to determine CDF, is the BV1REV4 model. This model contains the Level 1 PRA model for internal initiating events. The software used in the update process was RISKMAN. A Level 1 PRA presents the risk (that is, what can go wrong and what is the likelihood?) associated with core damage. For the updated PRA, core damage is defined as the uncovery and heatup of the reactor core to the point where prolonged cladding oxidation and severe fuel damage is anticipated. This condition is expected whenever the core exit temperatures exceed 1,200°F and the core peak nodal temperatures exceed 1,800°F.

The Beaver Valley Unit 1 internal events CDF is calculated to be 3.98E-06 /year. The fault tree method of quantification is binary decision diagram quantification, which provides an exact solution for split fraction values. The event tree quantification was calculated using a truncation cutoff frequency of 1.0E-14, or more than 8 orders of magnitude below the baseline CDF. The results of the CDF quantification of risk from internal events is summarized in Table 3.1.1.1-1 (Initiating Event Contribution to internal core damage), Table 3.1.1.1-2 (Basic Event Importance) and Table 3.1.1.1-3 (Component Importance). Contribution to internal events CDF from ATWS and SBO is presented below for information purposes.

	Contribution to Internal CDF (/year)
ATWS	3.85E-07
SBO	2.62E-07

The original PRA model (IPE submittal) was based on the BVPS-1 plant configuration circa 1988 and was calculated using a plant specific database that included equipment failures and maintenance history from January 1, 1980 until the end of 1988. The original PRA model was then updated for the IPEEE submittal (Reference 3) based on the BVPS-1 plant configuration at the end of 1993. The results presented in this report are based on an updated PRA model (BV1REV4), which has a "freeze date" of April 20, 2006 for the plant configuration, and a "freeze date" of December 31, 2005 for component failure data and initiating event data. Equipment unavailabilities were based on Maintenance Rule availability history from November 1, 1998 to December 31, 2005. This updated PRA model was also revised to include modeling enhancements.

Table 3.1.1.1-1: BV1REV4 Dominant Initiating Event Contribution to Internal Core Damage					
Initiator	**Description**	**Initiating Event Frequency**	**Contribution to Internal CDF**	**Percent of Internal CDF***	**Cumulative Percent of Internal CDF**
AOX	Loss of Emergency 4160V AC Orange	1.78E-02	6.64E-07	17%	17%
BPX	Loss of Emergency 4160V AC Purple	1.78E-02	6.43E-07	16%	33%
WCX	Loss of All River Water Systems	1.31E-06	2.66E-07	7%	40%
ELOCA	Excessive Loss of Coolant Accident	2.66E-07	2.66E-07	7%	46%
RTRIP	Reactor Trip	7.47E-01	2.18E-07	5%	52%
DPX	Loss of Emergency 125V DC Purple	4.80E-03	1.99E-07	5%	57%
TTRIP	Turbine Trip	6.52E-01	1.91E-07	5%	62%
PLMFWA	Partial Loss of Main Feedwater - ATWS	5.00E-01	1.55E-07	4%	66%
PLMFW	Partial Loss of Main Feedwater	5.00E-01	1.50E-07	4%	70%
LOSPE	Loss of Offsite Power - Extreme Weather Related	2.24E-03	1.44E-07	4%	74%
DOX	Loss of Emergency 125V DC Orange	4.80E-03	1.10E-07	3%	76%
IMSIV	Closure of One MSIV	2.00E-01	7.94E-08	2%	78%
IMSIVA	Closure of One MSIV - ATWS	2.00E-01	6.06E-08	1%	80%
EXFW	Excessive Feedwater Flow	1.65E-01	5.14E-08	1%	81%
EXFWA	Excessive Feedwater Flow - ATWS	1.65E-01	5.13E-08	1%	82%
TLMFW	Total Loss of Main Feedwater	4.14E-02	3.71E-08	1%	83%
SLOCN	Small LOCA, Nonisolable	2.66E-03	3.66E-08	1%	84%
MLOCAA	Medium Loss of Coolant Accident in Loop A	2.02E-05	3.39E-08	1%	85%
MLOCAB	Medium Loss of Coolant Accident in Loop B	2.02E-05	3.39E-08	1%	86%
MLOCAC	Medium Loss of Coolant Accident in Loop C	2.02E-05	3.39E-08	1%	87%
LCV	Loss of Condenser Vacuum	1.16E-01	3.36E-08	1%	88%
ISI	Inadvertent Safety Injection Initiation	8.12E-02	3.23E-08	1%	88%
ISIA	Inadvertent Safety Injection Initiation - ATWS	8.12E-02	2.47E-08	1%	89%
LOPF	Loss of Primary Flow	8.10E-02	2.32E-08	1%	90%
LOSPG	Loss of Offsite Power - Grid Centered	1.34E-02	2.21E-08	1%	90%
* Percentages are rounded off the whole numbers.					

Table 3.1.1.1-2 BV1REV4 Top 10 Basic Events by Risk Reduction Worth (Internal Events)				
Rank	Basic Event Name	Basic Event Description	RRW*	Associated SAMA
1	HVXCRW200	RW-200 Manual Valve Transfers Closed	1.15E+00	Cooling Water SAMAs
2	CBXO480VUS18N1	480V Breaker 480VUS-1-8N1 Transfers Open	1.10E+00	AC PWR SAMAs
3	CBXO480VUS19P1	480V Breaker 480VUS-1-9P1 Transfers Open	1.10E+00	AC PWR SAMAs
4	XXFRACTIONRODS	Fraction of RT Failures Caused by Control Rods Failing to Insert	1.08E+00	ATWS SAMAs
5	PPRPRW3	Common Header Pipe Break	1.08E+00	Cooling Water SAMAs
6	FRCTRIF05	Fraction of Time There is Insufficient Relief with 0 PORVs Blocked	1.08E+00	SAMA 156
7	DGSREEEG1	Diesel Generator EE-EG-1 Fails to Run After 1st Hour	1.06E+00	AC PWR SAMAs
8	DGSREEEG2	Diesel Generator EE-EG-2 Fails to Run After 1st Hour	1.05E+00	AC PWR SAMAs
9	BSORDCSWBD2	Failure of 125V DC Bus 2 DC-SWBD-2 During 24 hr Mission Time	1.05E+00	DC PWR SAMAs
10	BSOR480VUS18N	480V Bus 480VUS-1-8-N Fails During Operation	1.05E+00	AC PWR SAMAs
* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship: RRW = 1 / (1 - FV)				

Table 3.1.1.1-3 BV1REV4 Top 10 Components by Risk Reduction Worth (Internal Events)				
Rank	**Component Name**	**Component Description**	**RRW***	**Associated SAMA**
1	RW-200	Common River Water Header Isolation Valve	1.15E+00	Cooling Water SAMAs
2	EE-EG-1	No. 1 Emergency Diesel Generator	1.12E+00	AC PWR SAMAs
3	EE-EG-2	No. 2 Emergency Diesel Generator	1.11E+00	AC PWR SAMAs
4	480VUS-1-8N1	Incoming Supply Breaker From 4KVS-1AE-1E12	1.10E+00	AC PWR SAMAs
5	480VUS-1-9P1	Incoming Supply Breaker From 4KVS-1DF-1F12	1.10E+00	AC PWR SAMAs
6	RW-PIPE	River Water System Pipe	1.08E+00	Cooling Water SAMAs
7	DC-SWBD-2	125 VDC Switchboard #2	1.05E+00	DC PWR SAMAs
8	480VUS-1-8-N	480V Substation 1-8 Emergency Bus 1N	1.05E+00	AC PWR SAMAs
9	4KVS-1AE	4160 Emergency AC Bus 1AE	1.05E+00	AC PWR SAMAs
10	480VUS-1-9-P	480V Substation 1-9 Emergency Bus 1P	1.05E+00	AC PWR SAMAs

* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship:

$$RRW = 1 / (1 - FV)$$

3.1.1.2 Level 1 PRA Model Changes since IPE Submittal

The major Level 1 changes incorporated into each revision of the Beaver Valley Unit 1 PRA model are discussed below. The individual affect on CDF by incorporating each of these changes has not been analyzed. However, each change is listed in order of expected importance, with the top change being the most important.

BVPS-1 PRA Model History							
PRA Model	**Rev.**	**Date**	**Internal**		**Total**		**Comments**
			CDF	**LERF**	**CDF**	**LERF**	
BV1	0	10/01/92	2.14E-04	1.06E-05	-	-	IPE Model
BV1REV1	1	06/30/95	1.17E-04	5.85E-06	1.44E-04	7.11E-06	IPEEE model
BV1REV2	2	06/30/98	6.24E-05	7.06E-07	8.50E-05	9.14E-07	Integrated Level 1 and Level 2 models
BV1REV3	3	09/05/03	7.45E-06	9.98E-07	2.34E-05	9.99E-07	NEI 00-02 Peer Review A/B F&Os addressed
BV1REV4	4	06/02/06	3.98E-06	7.41E-08	1.95E-05	7.54E-08	RSG/ACC/EPU Model

Beaver Valley Unit 1 Revision 0

This revision represents the base case IPE quantification and resulted in a core damage frequency of 2.14E-04 / year for internal events.

Beaver Valley Unit 1 Revision 1

This revision represents the updated IPE PRA model that served as the baseline risk model for the IPEEE.

Changes made include implementation of IPE vulnerability enhancements, slight changes to the top event models to reflect plant modifications performed through 1993, and plant-specific data updates of component failures and maintenance through June 1993. These changes resulted in an internal events core damage frequency of 1.17E-04 / year.

Model changes associated with the vulnerability enhancements made to this revision consisted of the following two model modifications:

- Adding a new top event to credit the installation of the 4160V station crosstie from the Unit 2 emergency diesel generators to the 1AE emergency bus.
- Making revisions to the primary pressure relief top event for Anticipated Transient Without Scram (ATWS) events by taking full credit for the capacity of the three

pressurizer PORVs to reduce the unfavorable exposure time (UET).

Beaver Valley Unit 1 Revision 2

Beaver Valley Unit 1 Revision 2 was made with the following model modifications. The changes resulted in an internal events core damage frequency of 6.24E-05 / year.

- The updated model gave credit for the operators to depressurize the RCS during small break LOCAs, so that a low head safety injection pump can provide makeup and core cooling, given the failure of the high head safety injection system. The CDF definition was also changed so that both core exit temperatures exceeded 1,200°F and the core peak nodal temperatures exceeded 1,800°F must be present.
- The revised frequency included consideration of the station cross-tie connecting the 4KV normal buses of Beaver Valley Units 1 and 2. This cross-tie capability was credited in the IPEEE submittal, but only for the 1AE emergency bus. The revised cross-tie model permitted credit for the Unit 2 emergency diesel generators, if available, to power either Unit 1 emergency AC bus 1AE or 1DF, given the failure of both Unit 1 emergency diesel generators and a loss of offsite power.
- If a loss of the AC Orange Train (assumed to be the operating train in the PRA model) is the initiating event, the 125 DC Purple bus will get a demand signal to auto start the standby components immediately. If the AC Purple Train is unavailable, the battery charger will supply the load; if the battery charger fails the battery will supply the load for the following two hours. This is considered to provide sufficient time to start standby components before the battery drains. Therefore, the model in this revision now provided credit for either the DC bus 2 charger or batteries to supply the load to start standby components, whenever a loss of AC power to the normally operating equipment is the initiating event.

Beaver Valley Unit 1 Revision 3

Beaver Valley Unit 1 Revision 3 was made with the following model modifications and incorporated the PRA Peer Review resolutions to the category A and B Facts and Observations (F&Os). The changes resulted in an internal events core damage frequency of 7.45E-06 / year.

- The updated model used the latest industry methodology for determining Reactor Coolant Pump (RCP) seal LOCAs. This methodology is based on WCAP-15603, Rev. 0 (Reference 21); however, it is slightly modified to account for the NRC's preliminary comments reviewing WCAP-15603. This modification used a number 1 seal popping-and-binding failure probability P(PB1) of 0.025 (which is the same as the Brookhaven Model) instead of 0.0125. With this new RCP seal LOCA model there is a 78-percent probability that the seal leakage will not exceed 21 gpm per RCP during the loss of all seal cooling condition, which accounts for the installed high-temperature O-rings on all three RCPs.

- The revised RCP Seal LOCA frequency also included plant specific thermal-hydraulic analyses performed with Modular Accident Analysis Program (MAAP) 4.0.4, which now accounted for sequences that do not go to core melt during a 48-hour period, given that Auxiliary Feedwater (AFW) or Dedicated AFW is available, as non-core damage sequences. These analyses were performed for both Station Blackout and loss of all river water scenarios. RCP Seal LOCA sequences that uncover the core before 48 hours, but after 30 hours, now used an electric power recovery factor based on the probability of not recovering offsite power before core damage occurs using the Plant-Centered LOSP Recovery lognormal distribution reported in NUREG/CR-5496 (Reference 8) and the median probability of not recovering at least one emergency diesel generator at times greater than 24-hours (if available for recovery).
- The High Head Safety Injection (HHSI) / charging pump ventilation support system was removed from this PRA model update based upon FENOC analysis 8700-DMC-1559, Rev. 0, "BVPS-1 Charging Pump Cubicle Heatup Following a Design Basis Accident (DBA) and Loss of Ventilation, PRA Analysis" (Reference 9). The results of this analysis show that when crediting buoyancy driven air flow from the pump cubicles and using a more realistic 1-month post DBA runout condition in place of the assumed Environmental Qualification (EQ) 6-month post DBA runout condition, the HHSI/charging pumps would continue to operate for a 24-hour period following a complete loss of all ventilation.
- The initiating events data was based on WCAP-15210 (Reference 10) to develop a generic prior and then Bayesian updated using Beaver Valley Unit 1 actual plant experience. Based on the PRA Peer Review comments, Unit 1 actual plant experience from January 1, 1980 though December 31, 2001 was used for the Bayesian update. Additionally, LOCA initiating event frequencies were now based on the interim LOCA frequencies taken from Table 4.1 of the "Technical Work to Support Possible Rulemaking for a Risk-Informed Alternative to 10CFR50.46/GDC 35" , to account for aging-related failure mechanisms.
- The Electric Power Recovery model, updated with the latest system models, credited more scenarios with recovery of the fast bus transfer breakers, emergency diesel generators, and offsite grid.
- In response to PRA Peer Review comments on the ATWS model, operator credit to perform emergency boration was now given even if earlier actions to manually trip the reactor or insert control rods fail.
- The reactor trip breaker failure rates were now based on NUREG/CR-5500 (Reference 22) and then Bayesian updated using a more detailed analysis of Beaver Valley Unit 1 actual plant experience.
- Motor operated valve failure rates were based on NUREG-1715 (Reference 23) to develop a generic prior and then Bayesian updated using Beaver Valley Unit 1 actual plant experience.
- The SSPS split fractions were now based on a CAFTA model using BVPS-2 plant specific components and Westinghouse generic failure rates. This model was

developed as part of the risk-informed application for the Unit 2 Slave Relay Surveillance Test Interval Extension. These split fraction values were considered to be a better estimate than the previous Unit 1 PRA models, which were based on the Diablo Canyon SSPS model.

- The concerns of the PRA Peer Review on the interfacing system LOCA initiating event frequency were addressed using the latest industry information from NUREG/CR-5102 and NUREG/CR-5603. Additionally, the Monte Carlo value from this revised model was used for the initiating event frequency.
- Each of the emergency diesel generators have 2.5% of unavailability associated with them based on the then current INPO/WANO industry guidelines, which provides more hours for future on-line maintenance.

Beaver Valley Unit 1 Revision 4

Beaver Valley Unit 1 Revision 4 was made with the following model modifications and incorporated the Extended Power Uprate (EPU) to 2900 MWth, Replacement Steam Generators (RSG), and Atmospheric Containment Conversion (ACC). The changes resulted in an internal events core damage frequency of 3.98E-06 / year.

- The SGTR initiating event frequencies are now based on the replacement Model 54F (Alloy 690) steam generators installed during 1R17, which have a lower rupture frequency (6.96E-04 per SG per year) as opposed to the original Model 51 steam generators (1.48E-03 per SG per year). These replacement SGTR initiating event frequencies were calculated in 8700-DMC-1647,"Initiating Event Steam Generator Tube Rupture Frequency for Beaver Valley Unit 1 Usage in PRA Modeling" (Reference 11)
- The third train of station instrument air, consisting of an auto start, diesel driven station air compressor is included in the PRA model. This system also provides an air supply to the containment instrument air system.
- The emergency diesel generator unavailability is once again based on historical BVPS unavailability, since extended on-line maintenance beyond 72-hours would require the availability of an additional AC power source (i.e., spare diesel generator) capable of supplying safe shutdown loads during a station blackout, per Licensing Amendments 1A-268 & 2A-150. Therefore, it is believed that there is a low probability that the extended AOT would ever be implemented.
- The initiating events data is based on Westinghouse WCAP-15210, Revision 1, "Transient Initiated Event Operating History Database for U.S. Westinghouse NSSS Plants (1987 – 1997)" to develop a generic prior and then Bayesian updated using Beaver Valley Unit 1 actual plant experience from January 1, 1980 though December 31, 2005.
- The methodology used to calculate the human error probabilities (HEP) was changed from the Success Likelihood Index Methodology (SLIM) to the EPRI HRA Calculator. These new HEPs also used operator action timings based on plant specific MAAP thermal hydraulic analysis that included the EPU, RSG, and ACC.

- The updated model uses the latest NRC accepted methodology for determining RCP Seal LOCAs. This methodology is based on Westinghouse's WCAP-15603, Revision 1-A, (Reference 7). The use of this revision differs from the previous PRA model in that the 57 gpm RCP seal LOCA probability was reassigned to the 182 gpm seal LOCA, and now has a zero probability. This is due to the NRC review of the WCAP, which concluded that given the failure of the second stage seal the third stage seal failure probability is unity, since it is not designed to handle more than the normal operating pressure differential of a few psid. However, with this new RCP Seal LOCA model there is now a 79% probability that the seal leakage will not exceed 21 gpm per RCP during the loss of all seal cooling condition, which accounts for the installed high-temperature o-rings on all three RCPs.
- The revised RCP Seal LOCA frequency also includes plant specific thermal hydraulic analyses performed with MAAP DBA and accounts for full EPU conditions. Sequences that do not go to core melt during a 48 hour period, given that AFW or Dedicated AFW is available, are not counted as core damage sequences, since it is believed that an alternate source of power could be provided within this time frame to maintain the reactor in a safe stable state. These analyses were performed for both Station Blackout and loss of all river water scenarios.
- The loss of offsite power (LOSP) initiating event is now broken down into five separate initiators; (1) plant-centered, (2) grid-centered, (3) switchyard centered, (4) severe weather related, and (5) extreme weather related. The basis for these initiating event frequencies comes from NUREG/CR-INEEL/EXT-04-02326, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1986 – 2003 (Draft)," (Reference 12) that were Bayesian updated with BVPS-1 plant specific data.
- The offsite power restoration probability curves used in the electric power recovery analyses are also based on NUREG/CR-INEEL/EXT-04-02326 potential bus restoration data using a composite curve. The composite curve is a frequency-weighted average of the four individual LOSP category curves (it excluded the extreme weather related data), which was Bayesian updated with plant-specific LOSP frequencies. The electric power recovery factors are not credited for extreme weather related LOSP initiators.
- The consequential loss of offsite power probability following reactor trips was updated based on more recent industry and expert opinion data sources.

3.1.2 External Events

For external events, the development of a list of possible scenarios is similar to that for internal events. Because of this, the models for external events can take advantage of much of the work completed for internal events. Rather than develop new event trees for external events, use is made of the most appropriate event trees developed earlier for internal events. Only the changes needed to account for the unique aspects of the external events are required.

3.1.2.1 Internal Fires

The fire analysis employs a scenario-based approach that meets the intent of NUREG-1407 to systematically identify fire and smoke hazards and their associated risk impact to BVPS-1. The analysis was divided into two phases: (1) a spatial interactions analysis phase and (2) a detailed analysis phase. In the spatial interactions analysis phase, one or more fire and smoke hazard scenarios were developed for each plant location that can potentially initiate a plant transient or affect the ability of the plant to mitigate an accident. The scenarios developed in this phase are called location scenarios. Conservative assumptions were made in the assessment of scenario impacts to screen out location scenarios that have a relatively insignificant impact on plant safety.

In the detailed analysis phase, detailed scenarios were developed for the location scenarios that survived the spatial interactions analysis screening. One or several frequency reduction factors (geometry factor, severity factor, fire nonsuppression factor, and nonrecovery factor) were assessed for each detailed scenario. As each frequency reduction factor was assessed, conservatism introduced in the earlier phase was reduced and the complexity of the analysis progressively increased. Whenever one or more reduction factors led to the conclusion that the risk associated with a detailed scenario was relatively insignificant, the analysis for that detailed scenario would be halted. Each detailed scenario was evaluated iteratively until the scenario was considered to be relatively risk insignificant or all frequency reduction factors were assessed. The plant vulnerabilities to fire and smoke hazards were assessed by aggregating the risk impact of the subscenarios. The frequency of fire and smoke hazard-initiated core damage sequences was used as a measure of the potential for plant vulnerabilities.

The containment performance in response to fire threats, Fire Risk Scoping Study (FRSS) issues, and other special safety issues were also evaluated. Risk management options could then be identified to reduce the risk impact associated with these scenarios.

The major steps of the Beaver Valley Fire Individual Plant Examination for External Events (IPEEE) are summarized as follows:

- Phase 1: Spatial Interactions Analysis

    1. Information Gathering and Data Collection
    2. Preliminary Screening and Identification of Important Locations

3. Development of Location Scenarios
4. Quantitative Screening

- Phase 2: Detailed Analysis

5. Development and Analysis of Detailed Scenarios
6. Sensitivity/Uncertainty Analysis
7. Containment Performance Evaluation
8. Resolution of the FRSS and Other Safety Issues

The BVPS-1 Fire PRA has not been explicitly updated since the IPEEE. However, as the Fire sequences are dependent on internal events modeling, the Fire sequences have implicitly been partially updated with updates to the internal events models. Additionally, screened-out detailed scenarios that were considered to be relatively risk insignificant in the IPEEE, but close to the threshold (1.17E-07/yr at Unit 1), were reanalyzed and included in subsequent PRA model revisions. Results of the Fire PRA for BVPS-1 are provided in the following Table 3.1.2.1-1

Table 3.1.2.1-1: Fire PRA Results

	BVPS-1 PRA Model
Current Fire CDF (/year)	3.67E-06
IPEEE Fire CDF (/year)	1.75E-05

Beaver Valley Unit 1 IPEEE Information

From the IPEEE, there are no readily apparent vulnerabilities to fire events at BVPS-1. The discussion that follows highlights the most significant contributors, in terms of how the plant might be changed to reduce the already acceptable risk.

Two general areas for improvement are considered; i.e., the equipment impacts that may result from fires in key areas, and the plant response to the most risk significant postulated fires. The current controls in place at Beaver Valley are judged to be adequate to limit the frequency of fires from internal plant sources.

The extent of equipment impacted by a fire depends on the originating location and to a large extent the amount and arrangement of cables within the rooms affected. For many of the key fire subscenarios identified, the equipment impacts are limited. For example, both trains of river water may be disabled by the fire, but there may be no other plant impacts. For such scenarios, repositioning of equipment or the rerouting of selected cables may be effective at reducing the risks of core damage.

Possible changes that might affect the frequency of the top five fire subscenarios are presented in Table 3.1.2.1-2 (extracted from Table 7-1 of the BVPS-1 IPEEE) for BVPS-1. The frequency assessment of the key scenarios is consistent with the analysis in

Appendix R (Reference 14), in that, for the key scenarios, it accounts for operator recovery actions that may have been credited in the Appendix R analysis.

Table 3.1.2.1-2: BVPS-1 IPEEE Model/Design Enhancements

CDF Key Contributor	Model or Design Enhancement	IPEEE CDF Importance		Percent of Total CDF **	Status
		Percent of CDF	Risk Reduction Worth *		
Emergency 125V DC Battery Room Block Walls	Reevaluate block wall fragility, reinforce block walls, or shield batteries.	67.3 (Seismic)	0.5962 (Seismic)	4.2	The block walls have been evaluated and found satisfactory in accordance with both USI A-46 and IEB 80-11. This along with a low contribution to total CDF warrants no further action.
CV-3 Fire	Reroute River Water pump power cable.	24.4 (Fire)	0.7560 (Fire)	3.0	The low contribution to total CDF warrants no further action.
CS-1 Fire (SW Corner)	Refine Emergency Switchgear room heatup analysis to provide additional time margin.	15.3 (Fire)	0.8470 (Fire)	1.9	The low contribution to total CDF warrants no further action.
PA-1E Fire	Reroute CCR Pump or HHSI suction MOV cables.	13.7 (Fire)	0.9189 (Fire)	1.7	The low contribution to total CDF warrants no further action.
CS-1 Fire (NE Corner)	Reroute River Water or Auxiliary RW pump power and control cables.	11.5 (Fire)	0.8846 (Fire)	1.4	The low contribution to total CDF warrants no further action.
NS-1 Fire (South Wall)	Reroute River Water pump control cables or Auxiliary RW pump power cables.	7.9 (Fire)	0.9210 (Fire)	1.0	The low contribution to total CDF warrants no further action.

Notes: * The Risk Reduction Worth is the factor decrease in CDF that would be realized if the failure probability of the affected system were decreased to 0.0 (i.e., guaranteed success). ** Total CDF includes both internal and external events.

3.1.2.2 Seismic Events

A PRA was performed for internal initiating events on the Beaver Valley Power Station in satisfaction of the IPE requirements. To assess the risk contribution and significance of seismic-initiated events to the total plant risk, it was determined that the PRA method would also be used for the seismic analysis to meet the requirements of the IPEEE.

Beaver Valley selected the Seismic PRA option over the seismic margins option for the following reasons:

- With the existing PRAs for internal events that were developed to support the IPE and the decision to extend the PRA for all of the external events within the IPEEE scope, all severe accident issues are addressed within the context of an integrated PRA model that consistently treats all internal and external initiating events. This model rigorously accounts for all accident sequences resulting from any combination of internal and external events. The resulting risk information provided from this integrated approach was viewed as more useful to DLC management to make decisions about allocating resources to manage the risks of severe accidents.

- With the ability to link the Level 1 and Level 2 event trees as demonstrated in the IPE, the selected PRA approach was found to provide a more rigorous examination of potential containment vulnerabilities and seismic/systems interactions impacting containment effectiveness than was possible using the seismic margins approach.

The methodology selected is consistent with PRAs performed with the procedures contained in NUREG/CR-2300. In general, the methodology used in the analysis consisted of the following main steps:

- Seismic Hazard Analysis. Determination of the frequency of various potential peak ground accelerations (PGA) at the site, and an assessment of the likelihood of landslides and soil liquefaction.

- Fragility Analysis. Determination of the conditional failure probability of risk-related plant structures and components at peak ground accelerations.

- Plant Logic Analysis. Development of logic models that evaluate the potential structure and component failure scenarios. The models include seismic-induced failures that may initiate an accident scenario and may directly disable components or systems needed to successfully terminate the scenario. The models also include potential failures and unavailabilities of components due to nonseismic causes.

- Level 1/2 Integration. The linking of Level 1 seismic event trees with the Level 2 containment event tree for an integrated Level 2 PRA of seismic events and seismic/system integrations to examine containment effectiveness.

- Assembly and Quantification. Assembly of the seismic hazard, component fragilities and nonseismic unavailabilities, and plant logic models, including model quantification to obtain point estimates for core damage, plant damage state, release category, and scenario frequencies that result from seismic-initiated events.

- Uncertainty Quantification. Calculation of probability distributions for category (Level 2 results) and core damage frequencies (Level 1 results) that can be combined with the results from other initiating events.

The BVPS-1 Seismic PRA has not been explicitly updated since the IPEEE. However, as the seismic sequences are dependent on internal events modeling, the seismic sequences have implicitly been partially updated with updates to the internal events models. Additionally, the BVPS-1 Revision 3 PRA model revised the component seismic fragilities based on the September 10, 1999 response to the Nuclear Regulatory Commission's IPEEE Request for Additional Information, dated July 8, 1999. This response noted that following a review of the analysis, the BVPS median capacities for those structures and equipment for which the seismic fragilities were directly calculated were overestimated by approximately 36%. Incorporating these new component fragilities resulted in the modeling of additional Seismic Top Events, as well as, increasing the failure probabilities. Results of the Seismic PRA for BVPS-1 are provided in the following Table 3.1.2.2-1

Table 3.1.2.2-1: Seismic PRA Results	
	BVPS-1 PRA Model
Current Seismic CDF (/year)	1.19E-05
IPEEE Seismic CDF (/year)	9.07E-06 (Original) 1.29E-05 (RAI Revised)

Beaver Valley Unit 1 IPEEE Seismic Information

The IPEEE concluded that there are no readily apparent vulnerabilities to seismic events at BVPS-1. The discussion that follows highlights the most significant contributors, in terms of how the plant might be changed to reduce the already acceptable risk.

Two general areas for improvement were considered; i.e., the plant response to seismic-initiated failures and the equipment seismic fragilities.

For the top 50 highest frequency core damage sequences in the original IPEEE submittal, the conditional frequencies of core damage given the seismic initiating event and failures directly attributable to it are all 1.0. In the large majority of these sequences, either the seismic failures result in a station blackout, a loss of all DC control power, or the loss of all river water. In some of the top sequences, there may be two or more failures, which if they occurred alone, would each result in core damage. Therefore, it is concluded that options to improve the plant response to seismic events would not be effective in limiting risk. This conclusion was also reached in the IPEEE RAI response.

Although the offsite power grid and the 125V DC ERF Substation battery are assessed as having the weakest fragility curves of those modeled, the most risk significant seismic fragility is that of the 125V DC battery room block walls. Failure of these walls is assumed to result in the loss of both sets of emergency DC control power and eventual core damage. Enhancements to these block walls were considered and are presented in Table 3.1.2-1 (extracted from Table 7-1 of the BVPS-1 IPEEE) for BVPS-1.

Beaver Valley Unit 1 USI A-45 Resolution

Resolution of the external events portion of Unresolved Safety Issue A-45 was subsumed into the IPEEE requirements that allow plant-specific evaluation of the safety adequacy of decay heat removal systems.

The Beaver Valley Unit 1 PRA results provide indications of the importance of systems that directly perform the decay heat removal function. The IPEEE indicates the importance of systems that perform the decay heat removal function. Five classes of systems were considered: main feedwater, auxiliary feedwater, bleed and feed cooling, steam generator depressurization for RCS cooldown, and closed loop residual heat removal. Importance is measured by the percentage of core damage frequency attributable to sequences that involve failure of the indicated split fraction. The importance measures are not additive because more than one of the ranked split fractions may, and often do, fail in the same sequence.

Two event tree top events are used to represent the main feedwater system. Top Event "MF" represents the hardware failure modes under normal operations and Top Event "OF" represents the operator action to realign main feedwater after a plant trip, given that auxiliary feedwater fails. The most important main feedwater system failures occur in sequences for which main feedwater is lost due to the seismically caused loss of its support systems, i.e., split fraction MFF.

Top Event "AF" represents the auxiliary feedwater system. The most important auxiliary feedwater system failures are due to loss of all support systems to the motor-driven and turbine-driven pumps.

Feed and bleed cooling is modeled by four separate event tree top events: Top Event "HH" for the HHSI pumps, Top Event "HC" for the cold leg injection flow path, Top Event "VL" for the path from the RWST, and Top Event "OB" that models the bleed path via the pressurizer. Because of the credit taken for realigning the electric-driven main feedwater pumps, the Beaver Valley Unit 1 design minimizes the frequency of sequences involving failure of AFW and bleed and feed cooling, relative to other PWRs. Three of these four top events ("HC", "HH", and "VL") are also used to model high head safety injection in the event of a small LOCA.

Top Event "CD" models the action to depressurize the steam generators in sequences where it is desirable to cool down and depressurize the RCS. Steam generator depressurization helps to limit RCS leakage during a station blackout or a steam generator tube rupture with a stuck-open secondary side valve. As can be seen from the percentage of contribution listed in IPEEE Table 3-17, such failures are relatively unimportant to the core damage frequency.

Finally, the importance of cooling via the residual heat removal system is also indicated in IPEEE Table 3-17. The RHR system plays only a minor role in the determination of the core melt frequency. By design, this system is tripped off on a Phase B containment isolation signal. No sequences greater than 7.0E-09 per year involved failure of the RHR.

In summary, no particular vulnerabilities of the Beaver Valley Unit 1 systems that are used to perform decay heat removal have been identified. The majority of the seismic core damage frequency at Beaver Valley Unit 1 comes from loss of emergency AC and DC power caused by the seismic initiating event. No discernible frequency comes from failures of decay heat removal.

3.1.2.3 Other External Events

NUREG-1407 recommends a screening type approach, as shown in Figure 3.1.2.3-1 (taken from Figure 5-1 of NUREG-1407). The general methodology used at BVPS-1 follows the approach recommended by NUREG-1407 and consists of the following steps:

- Establishing a List of Plant-Specific Other External Events
- Progressive Screening
- Walkdown
- Documentation

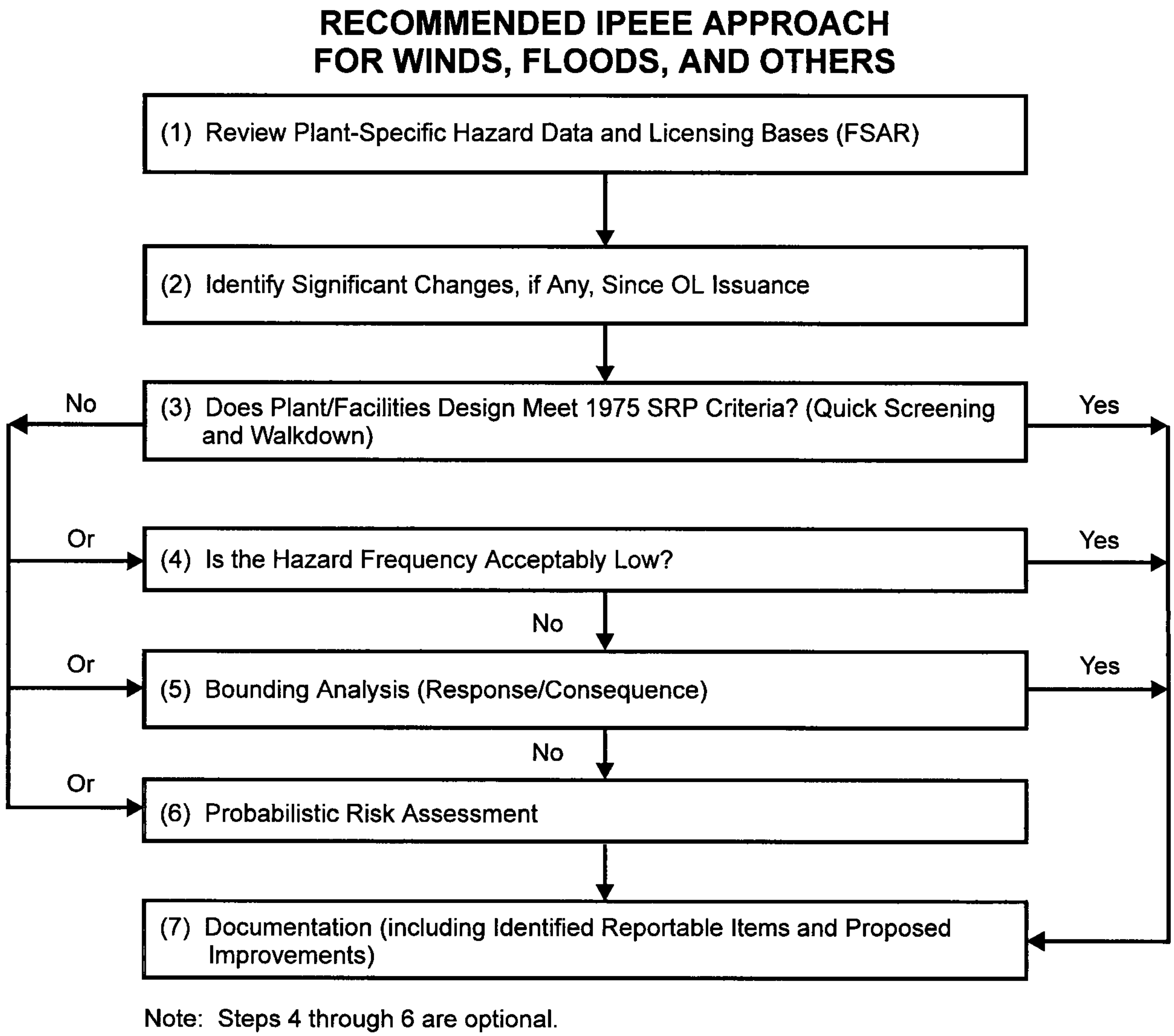

Figure 3.1.2.3-1: NUREG-1407 Screening Approach

Based on the results in the BVPS-1 IPEEE, it was concluded that the plant structures at the site are well designed to withstand the high wind associated hazards and that no potential vulnerability was identified.

Since the plant and facilities design meets the 1975 SRP criteria, and that there are no existing plant changes that could affect the plant hazard data or the licensing bases with respect to flooding, the core damage frequency due to external flooding was estimated to be less than 1.0E-06 per year for BVPS-1.

The NRC staff concluded, in the BVPS-2 IPEEE SER, that, according to GDC 4, GDC 19, and SRP Section 2.2.3, the BVPS plant is adequately protected and acceptable with respect to transportation and nearby facility hazards. This is also applicable to BVPS-1.

Based on the review of the lightning events that have occurred at the site, it was concluded that they were less severe than a complete loss of offsite power to BVPS-1. Also, according to Section 2.6 of NUREG-1407, the probability of a severe accident caused by lightning would be relatively low. Therefore, lightning is an insignificant contributor to core damage frequency for BVPS-1.

The contribution to the BVPS-1 total CDF from the other external events is less than 1.0E-06 per year, and as concluded in the BVPS-1 IPEEE, there are no vulnerabilities to the other external events at BVPS-1.

3.1.2.4 External Event Severe Accident Risk

External event severe accident risk assessment is integrated with the internal events risk; the PRA includes both internal and external. This assessment approach provides the means to evaluate SAMAs for both internal and external events impacts simultaneously without the need to separately estimate the impact of the potential improvements on external events.

3.2 LEVEL 2 PLANT SPECIFIC MODEL

The Level 2 PRA model determines release frequency, severity, and timing based on the Level 1 PRA, containment performance, and accident progression analyses.

3.2.1 Description of Level 2 PRA Model

The accident sequence analysis defines the manner in which expected plant response to each identified initiating event or initiating event category is represented and quantified. This accounts for successes and failures of safety functions and related systems, and human actions to determine whether or not core damage occurs. The result of the Level 1 accident sequence analysis is the definition of a set of event trees used to represent and quantify the accident sequences.

The Level 2 analysis extends the Level 1 analysis to investigate the release category potential for core damage end states found. A containment event tree (CET) is used to represent and quantify the release category potential when quantified with the Level 1 event trees.

The Level 2 analysis is highly interdependent with other Probabilistic Risk Assessment tasks. The accident sequence plant damage states (PDSs) define the categories of core damage sequences to be considered in the Level 2 analysis. The event tree used to represent and quantify the release category potential is linked to the event trees representing the Level 1 analysis.

Each end state of the plant model (front-end or Level 1) event trees defines an accident sequence that results from an initiating event followed by the success or failure of various plant systems and/or the success or failure of operators to respond to procedures or otherwise intervene to mitigate the accident. Each accident sequence has a unique signature due to the particular combination of top event successes and failures. Each accident sequence that results in core damage could be evaluated explicitly in terms of the accident progression and the release of radioactive materials, if any, into the environment. However, since there can be millions of such sequences, it is impractical to perform thermal-hydraulic analyses and CET split-fraction quantification for each accident sequence. Therefore, the Level 1 sequences are usually grouped into PDS (or accident class) bins, each of which collects all of those sequences for which the progression of core damage, the release of fission products from the fuel, the status of the containment and its systems, and the potential for mitigating source terms are similar. A detailed split-fraction analysis is then focused on specific sequences selected to represent risk-significant bins.

PDS bins have been used as the entry states (similar to initiating events for the plant model event trees) to the CETs. The PDS bins are characterized by thermodynamic conditions in the Reactor Coolant System (RCS) and the containment at the onset of core damage, and the availability or unavailability of both passive and active plant features that can terminate the accident or mitigate the release of radioactive materials into the environment.

However, this was not the case in the BVPS-1 PRA models, where the CET was linked directly to the Level 1 trees to generate the frequencies of the defined release categories. Although the CET was linked directly to the Level 1 trees, the concept of PDSs was retained to minimize the number of CET top event split fractions that must be calculated. Furthermore, the CET was quantified separately for a number of key PDSs to facilitate debugging of the rules used for assigning CET split fractions and binning sequences to appropriate release categories.

The PDSs are characterized in such a manner to facilitate Level 2 quantification. However, the core damage frequency need not be characterized using the same PDS bins. In fact, Level 1 results have been characterized using much broader bin definitions.

Representative accident sequences must be selected to quantify split-fraction values for the CET. If PDSs are defined, a representative accident sequence(s) is selected for each risk-significant PDS. These representative sequences are analyzed in detail with appropriate thermal-hydraulic and fission product transport codes such as the Modular Accident Analysis Program (MAAP), the Source Term Code Package (STCP), and/or the MELCOR program to characterize the timing of important events (such as the onset of severe core damage and reactor vessel melt-through) as well as the nature of the core damage, containment failure, and fission product release.

The BV1REV4 PDS groups are presented in Table 3.2.1-4.

PDS groups are evaluated in a Containment Event Tree. CET sequences are then grouped and binned in previously defined release category bins based on sequence and containment conditions as shown in Table 3.2.1-5 (Table 4.7-7 in the BVPS-1 IPE Summary Report submittal).

The IPE source term evaluation was based on radionuclide releases of 20 Beaver Valley release category bins plus an intact containment bin. However, in support of the SAMA, BVPS has elected to upgrade the source release fractions for select bounding release categories based on current plant specific MAAP-DBA analyses that account for EPU conditions. In support of SAMA evaluations it is not necessary to run a MAAP case to represent each individual IPE release class for BVPS (i.e., BV1 – BV21). The release categories identified in Table 3.2-1 are those that are applicable to the plant's Level 3 and SAMA evaluations and were re-evaluated using MAAP-DBA. The specific MAAP cases provided in the table were judged to be sufficient to represent each release category identified in the BVPS SAMA evaluation.

All MAAP-DBA cases were analyzed for 24 hours after the time of release, or demonstrated that a complete release has been produced (i.e., at least 98% of the noble gases have been released from containment).

The Level 2 quantification extends the Level 1 results of the Beaver Valley Unit 1 PRA to include the Level 2 results. This extension has been accomplished by linking the CET (discussed earlier in this section) to the Level 1 trees, and by assigning the end states of the linked Levels 1 and 2 trees to the appropriate release categories. For reporting, the release categories have been binned into four groups, as shown in Table 3.2.1-1. Basic Event Importances (Table 3.2.1-2) and Component Importances (Table 3.2.1-3) for the Large Early Release category group are provided for information.

Table 3.2.1-1: BV1REV4 Release Category Group Definition and Results

Release Type	Description	Associated CDF (per year)	Percentage of Total CDF
I	Large, early containment failures and bypasses	7.54E-08	0.4%
II	Small, early containment failures and bypasses	8.07E-06	41.3%
III	Late containment failures	1.04E-05	53.1%
IV	Long-term contained releases (intact containment)	1.01E-06	5.2%
Total Plant CDF		1.95E-05	100%

Table 3.2.1-2: BV1REV4 Basic Event Importances for Total Plant LERF by Risk Reduction Worth

Rank	Basic Event Name	Basic Event Description	RRW*	Associated SAMA
1	OGXXXX	Offsite Grid Fails Following Non-LOSP Initiator	4.67E+00	AC Power SAMAs
2	OPRSL3	Operator Fails to Gag Stuck Open SRV	1.52E+00	SAMA 164
3	AVFCTVMS101C	TV-MS-101C Fails to Close on Demand	1.09E+00	SGTR SAMAs
4	AVFCTVMS101B	TV-MS-101B Fails to Close on Demand	1.09E+00	SGTR SAMAs
5	AVFCTVMS101A	TV-MS-101A Fails to Close on Demand	1.09E+00	SGTR SAMAs
6	[CBFD52BYA CBFD52BYB CBFD52RTA CBFD52RTB]	Common Cause Failure on Demand of Reactor Trip Breakers	1.05E+00	ATWS SAMAs
7	CONTROLRODS	Control Rods Fail to Insert	1.04E+00	ATWS SAMAs
8	SVFCSVMS101C	SV-MS-101C Fails to Close on Demand	1.04E+00	SGTR SAMAs
9	SVFCSVMS102C	SV-MS-102C Fails to Close on Demand	1.04E+00	SGTR SAMAs
10	SVFCSVMS103C	SV-MS-103C Fails to Close on Demand	1.04E+00	SGTR SAMAs

* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship:
RRW = 1 / (1 - FV)

Table 3.2.1-3: BV1REV4 Component Importances for Total Plant LERF by Risk Reduction Worth				
Rank	**Component Name**	**Component Description**	**RRW***	**Associated SAMA**
1	TV-MS-101C	Loop 1C Main Steam Trip Valve	1.09E+00	SGTR SAMAs
2	TV-MS-101B	Loop 1B Main Steam Trip Valve	1.09E+00	SGTR SAMAs
3	TV-MS-101A	Loop 1A Main Steam Trip Valve	1.09E+00	SGTR SAMAs
4	1F/L-B10-ROD	Control Rods Fail to Insert	1.04E+00	ATWS SAMAs
5	SV-MS-101C	SV-MS-101C Fails to Close on Demand	1.04E+00	SGTR SAMAs
6	SV-MS-102C	SV-MS-102C Fails to Close on Demand	1.04E+00	SGTR SAMAs
7	SV-MS-103C	SV-MS-103C Fails to Close on Demand	1.04E+00	SGTR SAMAs
8	SV-MS-101B	SV-MS-101B Fails to Close on Demand	1.04E+00	SGTR SAMAs
9	SV-MS-102B	SV-MS-102B Fails to Close on Demand	1.04E+00	SGTR SAMAs
10	SV-MS-103B	SV-MS-103B Fails to Close on Demand	1.04E+00	SGTR SAMAs
* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship: RRW = 1 / (1 - FV)				

Table 3.2.1-4
BV1REV4 Level 1 Sequence Groupings

RCS Pressure at Core Damage	Containment Bypassed		Containment Not Isolated	Containment Isolated	
	Small (SBYP)	Large (LBYP)		With Heat Removal (WCHR)	No Heat Removal (NOHR)
Low (L)) (0-200 psia)	LOSBYP	LOLBYP	LONISO	LOWCHR	LONOHR
Medium (MD) (200-600 psia)	MDSBYP	--	MDNISO	MDWCHR	MDNOHR
High (HI) (600-2,000 psia)	HISBYP	--	HINISO	HIWCHR	HINOHR
System Setpoint (SY) (>2,000 psia)	SYSBYP	--	SYNISO	SYWCHR	SYNOHR

Table 3.2.1-5 Beaver Valley Unit 1 PRA Release Categories

Release Category	RCS Pressure			Containment Failure							Sprays?			Ex-Cont Retention*			Draft NUREG-1150 Dry PWR Cat	Major Release Type**
	High	Med	Low	Intact	Early	Late	Large	Small	Lrg Byp	Sm Byp	Yes	Partial	No	None	Mod-erate	Signif-icant		
BV1	X				X		X						X	X			1, 6, 16	I
BV2	X				X		X				X—	—X		X			2, 7, 17	I
BV3		X	X		X		X						X	X			3, 5, 6, 18	I
BV4		X	X		X		X				X—	—X		X			4, 7, 19	I
BV5	X—	—X			X			X				X—	—X		X		6	
BV6	X—	—X			X			X			X				X		7	II
BV7			X		X			X				X—	—X		X		6	
BV8			X		X			X			X				X		7	
BV9	X—	—X				X	X						X	X			9	
BV10	X—	—X				X	X				X—	—X		X			8	
BV11			X			X	X						X	X			9	
BV12			X			X	X				X—	—X		X			8	
BV13	X—	—X				X		X				X—	—X		X		10	III
BV14	X—	—X				X		X			X				X		10	
BV15			X			X		X				X—	—X		X		10	
BV16			X			X		X			X				X		10	
BV17	X—	—X—	—X			X		X			X—	—X—	—X			X	13, 14	
BV18	X—	—X—	—X						X—	—X	X—	—X—	—X	X			12	I
BV19			X						X		X—	—X—	—X		X		11	
BV20	X—	—X								X	X—	—X—	—X			X	11	II
BV21	X—	—X—	—X	X							X			X			15–No Failure	IV

* "None" = direct or nearly direct to atmosphere (DF < 2), "Moderate" = through large building or with limited flooding (DF = 2 to 10), "Significant" = through deep pool or isolated steam generator (DF > 10)

** I = Large, Early Release, or Bypass, S/T equal to or greater than PWR4 (WASH-1400)
II = Small, Early Release, S/T less than PWR4 (WASH-1400)
III = Late Release, very low S/T
IV = Long-Term Containment Integrity, Minimal Release
X------X Indicates that the Release Category groups together two or more different characteristics

Table 3.2.1-6: BVPS Release Categories Reanalyzed Using MAAP-DBA

Release Category	IPE Release Category Description	Representative MAAP Accident Sequence	Assumed Containment Failure Area
BV1	High RCS Pressure, Early, Large, No CHR.	SBO with no AFW and no sprays available. Large containment failure.	1 ft^2
BV3	Med/Low RCS Pressure, Early, Large, No CHR.	LLOCA with no active injection and no sprays. Large containment failure.	1 ft^2
BV5	High/Med RCS Pressure, Early, Small, Partial/No CHR, Yes Aux. Building.	SBO with no AFW and no sprays available. LOCI with a small release through the aux. building.	0.1 ft^2
BV7	Low RCS Pressure, Early, Small, Partial/No CHR, Yes Aux. Building.	LLOCA with no active injection and no sprays. LOCI with a small release through the aux. building.	0.1 ft^2
BV9	High/Med RCS Pressure, Late, Large, No CHR.	SBO with no AFW and no sprays available. Large containment failure due to over-pressurization.	1 ft^2
BV10	High/Med RCS Pressure, Late, Large, Partial CHR.	TLOFW with no active injection and partial sprays available. Large containment failure from H_2 burn.	1 ft^2
BV12	Low RCS Pressure, Late, Large, Partial CHR.	LLOCA with no active injection and partial sprays available. Large containment failure from H_2 burn.	1 ft^2
BV13	High/Med RCS Pressure, Late, Small, Partial/No CHR, Yes Aux. Building.	SBO with no AFW and no sprays available. Small containment failure due to over-pressurization.	0.2 ft^2
BV15	Low RCS Pressure, Late, Small, Partial/No CHR, Yes Aux. Building.	LLOCA with no active injection and no sprays available. Small containment failure due to over-pressurization.	0.2 ft^2
BV17	High/Med/Low RCS Pressure, Late, Small, Yes/Partial/No CHR, Ground.	SBO with no AFW and no sprays available. Failure through base of containment.	1 ft^2
BV18	High/Med/Low RCS Pressure, Large/Small Bypass, Yes/Partial/No CHR, Little or No Ex-Cont Retention.	SGTR with a TLOFW, no active injection and no sprays available. Direct release through stuck open MSSVs,	Containment Bypassed (DF=1.0)
BV19	Low RCS Pressure, Large Bypass, Yes/Partial/No CHR, Moderate Ex-Cont. Retention.	Large ISLOCA through low pressure injection system, no injection and no sprays available. Aux. building release below water level (flooded building provides scrubbing).	Containment Bypassed (DF=4.3)
BV20	High/Med RCS Pressure, Small Bypass, Yes/Partial/No CHR, Significant Ex-Cont. Retention.	Small ISLOCA through low pressure injection system, no injection and no sprays available. Aux. building release below water level (flooded building provides scrubbing).	Containment Bypassed (DF=10)
BV21	High RCS Pressure, Intact Containment, CHR available.	SLOCA with a TLOFW, no injection during recirculation and sprays available. No containment failure.	2.5E-05 ft^2 (Based on 0.1% volume / day leakage)

3.2.2 Level 2 PRA Model Changes Since IPE Submittal

The major Level 2 changes incorporated into each revision of the Beaver Valley Unit 1 PRA model are discussed below. The individual affect on risk by incorporating each of these changes has not been analyzed.

Beaver Valley Unit 1 Revision 0

This revision represents the base case IPE quantification and resulted in a large early release frequency of 1.06E-05 / year for internal events.

Beaver Valley Unit 1 Revision 1

This revision represents the base case IPEEE quantification and resulted in a large early release frequency of 5.85E-06 / year for internal events. This reduction in LERF was due to Level 1 PRA model changes. There were no changes to the Level 2 PRA model.

Beaver Valley Unit 1 Revision 2

There was only 1 major Level 2 change incorporated into this updated BVPS-1 PRA model. This change was implemented due to a reevaluation of the impact of direct containment heating (DCH) on the frequency of large, early releases at Beaver Valley Units 1 and 2.

The Direct Containment Heating issue was identified in the NRC's Revised Severe Accident Research Plan as an important issue for resolution because of its potential for early containment failures. DCH was recognized to be a potential by which sensible heat energy can be transferred directly to the reactor vessel and subsequent blowdown of the molten debris and RCS fluids into the containment atmosphere. If the RCS pressure is sufficiently high, the blowdown of the RCS fluid through an opening in the bottom head of the reactor vessel can entrain molten core debris in the high-velocity blowdown gas and eject fragmented particles from the reactor cavity into the containment. This series of events is referred to as high pressure melt ejection.

The Beaver Valley IPE submittals were based on an understanding of DCH phenomena as it was portrayed in the documentation (NUREG-1150 and NUREG/CR-4551) for the NRC's probabilistic assessment of severe accidents of five plants. Since that time, the state of knowledge regarding DCH phenomena evolved as additional experiments and analyses were performed. Two subsequent reports, NUREG/CR-6109 (Reference 17) and NUREG/CR-6338 (Reference 18) were issued by the NRC that relate to the resolution of DCH for Westinghouse plants with large, dry containments, including the Beaver Valley subatmospheric containments.

The conclusion of these reports is that the intermediate compartment traps most of the debris dispersed from the reactor cavity and that the thermal-chemical interactions during this dispersal process are limited by the incoherence in the steam blowdown and melt entrainment process.

Based on these new reports, the split fraction values for determining large, early containment failures (i.e., the product of C2 and L2) have reduction factors ranging from approximately 42 to more than 30,000 when compared to the IPE submittal.

This change to the Level 2 model contributed to a large early release frequency of 7.06E-07 / year for internal events.

Beaver Valley Unit 1 Revision 3

Beaver Valley Unit 1 Revision 3 was made with the following model modifications. These changes contributed to a large early release frequency of 9.98E-07 / year for internal events.

There were four major Level 2 changes incorporated into the updated Beaver Valley Unit 1 PRA model. Three of these changes dealt with sequences involving induced SGTRs, large containment failures due to early hydrogen burns, and large containment failures due to alpha-mode (in-vessel steam explosions). Based on Westinghouse and industry state-of-the-art knowledge of these containment phenomenologies, it was then believed that the probabilities of these occurring are extremely low for large, dry containments (that is, non ice-condenser) and are not credible in large containment failures or bypasses.

The fourth change altered the way steam generator tube ruptures were accounted for in the LERF definition. In this PRA model update, only steam generator tube ruptures sequences that have a depleted RWST or have a loss of all secondary cooling were considered to be LERF contributors. It was assumed that leakage from the RCS would continue indefinitely through the faulted steam generator and the core would uncover after the RWST depletes. This is in agreement with WCAP-15955 (Reference 19), “Steam Generator Tube Rupture PRA Notebook”.

Beaver Valley Unit 1 Revision 4

There were no specific changes to the Beaver Valley Unit 1 Level 2 model in this revision. Changes to the Level 1 model resulted in a large early release frequency of 7.41E-08 / year for internal events.

Based on a review that was performed to identify the effects of the EPU and the contributors to the Large Early Release conditional probability, there were no Level 2 changes required due to the BVPS-1 containment conversion. The sub-atmospheric containment modeling in the previous BVPS-1 PRAs assumed no large pre-existing containment isolation failures, due to the inability to maintain a containment vacuum. This assumption remains valid for EPU and the slightly subatmospheric conditions now existing, as the containment vacuum pumps are not expected to maintain the slightly sub-atmospheric condition for large pre-existing containment isolation failures, as well.

However, there were two major contributors to the reduction in the Level 2 LERF incorporated into the updated BVPS-1 PRA model. These consisted of the replacement steam generators installed during 1R17, and taking credit for improved procedures for isolating LOCAs outside containment. Since the replacement steam generators have a lower tube rupture frequency, the contribution to LERF via containment bypass events initiated by SGTRs that are either faulted with the RWST depleted or with failures of auxiliary feedwater that lead to an unscrubbed release, is reduced. The other major reduction in LERF is due to taking credit for operators to isolate another type of containment bypass event, initiated by interfacing systems LOCAs outside containment. This guidance is provided in emergency operating procedure ECA-1.2 "LOCA Outside Containment", which was enhanced to have operators identify and isolate the break by closing MOV-1SI-890C, the low head safety injection (LHSI) valve to the RCS cold legs. Performing this action would terminate the most probable interfacing systems LOCA break f low, which is postulated to occur in the LHSI lines; thereby, reducing its contribution to LERF.

3.3 MODEL REVIEW SUMMARY

Regulatory Guide (RG) 1.174 (Reference 38), Section 2.2.3 states that the quality of a PRA analysis used to support an application is measured in terms of its appropriateness with respect to scope, level of detail and technical acceptability, and that these are to be commensurate with the application for which it is intended.

The PRA technical acceptability of the model used in the development of this Severe Accident Mitigation Alternatives application has been demonstrated by a peer review process. The peer review was conducted in July 2002, by the [former] Westinghouse Owner's Group, with the final documentation of the review issued in December 2002. The overall conclusions of the peer review were:

> All of the technical elements were graded as sufficient to support applications requiring the capabilities defined for grade 2. The BVPS PRA thus provides an appropriate and sufficiently robust tool to support such activities as Maintenance Rule implementation, supported as necessary by deterministic insights and plant expert panel input.
>
> All of the elements were further graded as sufficient to support applications requiring the capabilities defined for grade 3, e.g., risk-informed applications supported by deterministic insights but in some cases this is contingent upon implementation of recommended enhancements.

After the peer review, the preliminary Category A and B facts and observations that potentially impacted the model were entered into the BVPS Corrective Action Program, dispositioned, and incorporated into updated PRA model. Although the facts and observations (F&Os) were written for the BVPS-2 model, if applicable, the resolution was applied to the BVPS-1 model as well. All Category A and B F&Os were implemented on Unit 1. Those models have since undergone another revision, but the incorporated resolution of Category A and B F&Os were maintained in the revision. The BVPS-1 Category A facts and F&Os and dispositions are summarized in the following paragraphs.

In addition, FENOC provided summaries of the BVPS Peer Review Category A and B F&Os in the following previously docketed letters:

- Pearce/USNRC, Beaver Valley Power Station, Unit No. 2, BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests No. 180, dated October 24, 2003, Serial L-03-160.
- Pearce/USNRC, Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66 and BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests Nos. 306 and 176, dated October 29, 2004, Serial L-04-141.

Category A Observations

F&O 1
Summary: This observation was identified in the Accident Sequence Analysis Sub-element regarding the RCP seal LOCA model. It was recognized that the BVPS RCP seal LOCA model used the WOG 2000 as a basis, but in a way that is more optimistic than most other Westinghouse plants. The BV2REV3A PRA model, RCP seal LOCA success criteria was developed from best estimate MAAP runs performed specifically for BVPS-2. Since certain MAAP results did not go to core uncovery in the assumed 24-hour mission time for the smaller break seal LOCA sizes, they were binned into the success (non CDF) end state, even though electric power or service water was not restored. The peer review team felt that additional MAAP analyses should be performed to investigate the impact of varying MAAP input parameters on the resultant time to core uncovery, and extend the run time to show stable plant conditions.

Resolution: Additional MAAP uncertainty cases for BVPS-1 were performed using pessimistically biased values along with setting input parameters to their high or low limits. These cases were run out to 48-hours or until core damage occurred. The success state for the BV1REV3 PRA model was redefined as any case (including uncertainties) that did not go to core damage before 48-hours. For cases that went to core damage before 48-hours but after 24-hours, additional electric power recovery values were used, based on NUREG/CR-5496. For cases that lead to core uncovery before 24-hours, a plant specific electric power recovery model was used. If electric power recovery was successful for these cases, the sequence was also binned to the success end state.

F&O 2
Summary: This observation was identified in the Human Reliability Analysis (HRA), Post-Initiator Human Actions Sub-element. It was observed that the BVPS human error rates were developed using the Success Likelihood Index Methodology (SLIM) based on calibration curves from other plant HRAs from the mid-1980's. The peer review team recommended that these calibration curves be updated with current operator performance in the nuclear power industry.

Resolution: As a resolution to this PRA Peer Review observation all operator actions having a Risk Achievement Worth (RAW) greater than 2 (generally accepted as the risk significant threshold) were compared to similar actions for all Westinghouse plants by using the WOG/B&WOG PRA Comparison Database (Revisions 2 and 3). Additionally, a smaller subset of these plants was also looked at. These consisted of; Westinghouse 3-loop plants (since these were assumed to have similar operation action completion times based on plant power to heatup volume ratios), plants that also used the SLIM process, and Indian Point 2, which received a superior finding in their Human Reliability Analysis peer review.

The results of this comparison show that for the operator actions that were compared, the human error rates used in the BV1REV3 PRA model are all within the range of both comparison groups defined above. It is therefore believed that the basic error curves used in the calibration of the BV1REV3 HRA are not grossly out of date, and that the current human error rates used in the PRA model are acceptable as is. Moreover, as a final resolution to this observation, future BVPS PRA models will use the EPRI HRA Calculator, which uses a more current and robust methodology.

F&O 3
Summary: This observation was identified in the Human Reliability Analysis, Dependence Among Actions Sub-element. It was observed that the BVPS HRA did not have a documented process to perform a systematic search for dependent human actions credited on individual sequences and a method to adjust dependencies between multiple human error rates in the same sequence. The peer review team recommended that a robust technique be developed, documented, and used for the identification and quantification of dependent human error rates (HERs).

Resolution: In the initial development of the IPE HRA, an effort was made to eliminate the dependency between human actions by adjusting the split fraction value of the second dependent action, given that the first action failed. For example, if the operators failed to manually reestablish Main Feedwater following the failure of Auxiliary Feedwater, the human error rate for implementing Bleed and Feed cooling later in the accident progression was adjusted upwards. If the dependent actions were required to take place in the same period of time during the accident progression, the second dependent action was assigned to be a guaranteed failure. For example, if the operators failed to cooldown and depressurize the RCS by using the secondary coolant system, no credit was given to the operators to depressurize the RCS using the Pressurizer PORVs.

However, as a resolution to this PRA Peer Review observation a method was established to verify that all dependent operator actions were captured by reviewing sequences with two or more failed split fractions that have a contribution from human actions. Of the sequences reviewed, the human actions were either previously adjusted during the IPE HRA, or were determined to be independent between split fractions. This independence was based on the actions not being conducted by the same set of operators (e.g., control room Reactor Operator action vs. local Auxiliary Plant Operator action), or different procedures being used separated by sufficient time in the accident progression (e.g., actions to makeup to the RWST given SI recirculation failures, following operator actions to align a spare Service Water pump earlier in the accident sequence progression).

Human actions that are modeled in a single top event have appropriate dependencies modeled in the event tree logic and rules. Moreover, as a final resolution to this observation, future BVPS PRA models will use the EPRI HRA Calculator, which uses a more current and robust methodology to identify human action dependencies.

3.4 LEVEL 3 PRA MODEL

The BVPS-1/2 Level 3 PRA model determines off-site dose and economic impacts of severe accidents based on the Level 1 PRA results, the Level 2 PRA results, atmospheric transport, mitigating actions, dose accumulation, early and latent health effects, and economic analyses.

The MELCOR Accident Consequence Code System (MACCS2) Version 1.13.1 was used to perform the calculations of the off-site consequences of a severe accident. This code is documented in NUREG/CR-6613 (Reference 28), "Code Manual for MACCS2: Volumes 1 and 2."

Plant-specific release data included the time-dependent nuclide distribution of releases and release frequencies. The behavior of the population during a release (evacuation parameters) was based on plant and site-specific set points. These data were used in combination with site-specific meteorology to simulate the probability distribution of impact risks (both exposures and economic effects) to the surrounding 50-mile radius population as a result of the release accident sequences at Beaver Valley.

The following sections describe input data for the MACCS2 (Reference 28) analysis tool. The analyses are provided in References 32-35.

3.4.1 Population Distribution

The population surrounding the Beaver Valley Power Station site, up to a 50 mile radius, was estimated based on the most recent United States Census Bureau decennial census data. Details are provided in "Calculation Package for Population Projections – Beaver Valley Power Station" (Reference 29). The population distribution was estimated in 9 concentric bands at 0 to 1 mile, 1 to 2 miles, 2 to 5 miles, 5 to 10 miles, 10 to 15 miles, 15 to 20 miles, 20 to 30 miles, 30 to 40 miles, and 40 to 50 miles, and 16 directional sectors with each direction consisting of 22.5 degrees. The population was projected to the year 2047 by calculating an annual growth rate for each county in the 50 mile radius derived from state and national population projections. Geometric growth rates were calculated for each county in Ohio and Pennsylvania based on 2030 county projections. However, if the county population had decreased from 2000 to 2030, it was assumed there was no growth through 2030 (i.e., the 2030 population was equal to the 2000 population), and the national growth rate was applied from 2030 to 2047 to obtain an overall multiplier fore the 2047 projection. For West Virginia, projections were available through 2050. The annual growth rate was applied to obtain a 2047 multiplier, unless a negative growth rate existed, in which case no growth was assumed. The population distribution used in this analysis is provided in the following table.

Table 3.4.1-1 Population Projections Used in SAMA Analysis

From Radius	To Radius	Direction	Code	2000 Population	2047 Population
0	1	N	1	0	0
0	1	NNE	2	0	0
0	1	NE	3	93	110
0	1	ENE	4	38	45
0	1	E	5	88	104
0	1	ESE	6	0	0
0	1	SE	7	7	8
0	1	SSE	8	0	0
0	1	S	9	0	0
0	1	SSW	10	0	0
0	1	SW	11	2	2
0	1	WSW	12	0	0
0	1	W	13	0	0
0	1	WNW	14	0	0
0	1	NW	15	132	156
0	1	NNW	16	53	63
1	2	N	17	197	232
1	2	NNE	18	62	73
1	2	NE	19	4	5
1	2	ENE	20	7	8
1	2	E	21	74	87
1	2	ESE	22	64	76
1	2	SE	23	116	137
1	2	SSE	24	22	26
1	2	S	25	18	21
1	2	SSW	26	35	41
1	2	SW	27	25	30
1	2	WSW	28	73	86
1	2	W	29	141	166
1	2	WNW	30	0	0
1	2	NW	31	1,651	1,948
1	2	NNW	32	470	555
2	5	N	33	835	985
2	5	NNE	34	1,016	1,199
2	5	NE	35	1,130	1,333
2	5	ENE	36	683	806
2	5	E	37	1,039	1,226
2	5	ESE	38	713	841
2	5	SE	39	284	335
2	5	SSE	40	637	752
2	5	S	41	486	573
2	5	SSW	42	742	876
2	5	SW	43	619	730
2	5	WSW	44	217	256
2	5	W	45	723	853

Table 3.4.1-1 Population Projections Used in SAMA Analysis (Cont.)

From Radius	To Radius	Direction	Code	2000 Population	2047 Population
2	5	WNW	46	802	946
2	5	NW	47	1,753	2,069
2	5	NNW	48	573	676
5	10	N	49	2,317	2,734
5	10	NNE	50	3,875	4,573
5	10	NE	51	18,262	21,549
5	10	ENE	52	14,995	17,694
5	10	E	53	19,461	22,964
5	10	ESE	54	7,307	8,606
5	10	SE	55	1,589	1,840
5	10	SSE	56	1,777	2,090
5	10	S	57	4,734	5,586
5	10	SSW	58	1,284	1,512
5	10	SW	59	3,604	3,875
5	10	WSW	60	1,886	1,918
5	10	W	61	19,534	21,213
5	10	WNW	62	7,332	8,652
5	10	NW	63	2,156	2,544
5	10	NNW	64	1,283	1,514
10	15	N	65	4,297	5,070
10	15	NNE	66	20,102	23,720
10	15	NE	67	18,866	22,262
10	15	ENE	68	13,403	15,810
10	15	E	69	18,133	20,507
10	15	ESE	70	31,028	31,750
10	15	SE	71	5,136	5,187
10	15	SSE	72	1,105	1,132
10	15	S	73	1,064	1,099
10	15	SSW	74	5,120	5,285
10	15	SW	75	9,357	9,802
10	15	WSW	76	1,931	2,095
10	15	W	77	6,926	7,980
10	15	WNW	78	3,491	4,119
10	15	NW	79	2,716	3,205
10	15	NNW	80	1,975	2,331
15	20	N	81	2,679	3,161
15	20	NNE	82	19,651	23,188
15	20	NE	83	8,256	10,097
15	20	ENE	84	26,225	35,104
15	20	E	85	20,890	21,130
15	20	ESE	86	32,047	32,367
15	20	SE	87	20,102	20,303
15	20	SSE	88	5,210	5,342
15	20	S	89	5,479	5,643
15	20	SSW	90	23,299	23,522
15	20	SW	91	6,325	7,364
15	20	WSW	92	1,568	1,850

Table 3.4.1-1 Population Projections Used in SAMA Analysis (Cont.)

From Radius	To Radius	Direction	Code	2000 Population	2047 Population
15	20	W	93	1,535	1,811
15	20	WNW	94	3,151	3,718
15	20	NW	95	5,793	6,836
15	20	NNW	96	9,801	11,565
20	30	N	97	40,448	47,729
20	30	NNE	98	25,927	31,193
20	30	NE	99	11,544	15,668
20	30	ENE	100	26,859	36,797
20	30	E	101	73,055	77,064
20	30	ESE	102	410,196	414,298
20	30	SE	103	227,938	230,716
20	30	SSE	104	39,083	40,229
20	30	S	105	5,494	5,656
20	30	SSW	106	38,710	41,558
20	30	SW	107	20,523	24,217
20	30	WSW	108	5,090	6,155
20	30	W	109	4,182	5,480
20	30	WNW	110	10,727	12,776
20	30	NW	111	33,243	39,227
20	30	NNW	112	38,242	45,126
30	40	N	113	27,393	32,324
30	40	NNE	114	14,394	17,649
30	40	NE	115	20,468	28,041
30	40	ENE	116	52,734	72,065
30	40	E	117	88,641	97,229
30	40	ESE	118	343,130	347,829
30	40	SE	119	114,676	116,792
30	40	SSE	120	49,039	50,510
30	40	S	121	10,274	10,553
30	40	SSW	122	35,720	38,675
30	40	SW	123	10,554	12,454
30	40	WSW	124	6,314	8,164
30	40	W	125	15,333	21,441
30	40	WNW	126	25,741	30,543
30	40	NW	127	19,379	22,864
30	40	NNW	128	218,945	258,355
40	50	N	129	67,035	79,101
40	50	NNE	130	26,361	31,533
40	50	NE	131	9,705	13,035
40	50	ENE	132	31,197	37,772
40	50	E	133	43,404	48,911
40	50	ESE	134	115,071	120,818
40	50	SE	135	79,774	83,809
40	50	SSE	136	21,216	21,842
40	50	S	137	5,221	5,321
40	50	SSW	138	72,617	79,681
40	50	SW	139	12,337	14,558

Table 3.4.1-1 Population Projections Used in SAMA Analysis (Cont.)

From Radius	To Radius	Direction	Code	2000 Population	2047 Population
40	50	WSW	140	9,276	11,210
40	50	W	141	19,628	24,920
40	50	WNW	142	83,296	97,999
40	50	NW	143	26,594	30,210
40	50	NNW	144	123,093	145,250
			Total	**3,273,502**	**3,607,001**

3.4.2 Economic Data

The Environmental Protection Agency's computer program SECPOP was the basis for the economic data used in the offsite evaluations done in this analysis. This code utilized county economic factors derived from the 2000 census and various other government sources dated 1997 to 1999. For the preparation of data for the Beaver Valley model, the county data file was updated to circa 2002 for the 23 counties within 50 miles of the plant. Reference 33 provides the input data used in this analysis:

Variable	Description	BVPS 1/2 Value
DPRATE[1]	Property depreciation rate (per yr)	0.20
DSRATE[1]	Investment rate of return (per yr)	0.12
EVACST[2]	Daily cost for a person who has been evacuated ($/person-day)	$49
POPCST[2]	Population relocation cost ($/person)	$13,727
RELCST[2]	Daily cost for a person who is relocated ($/person-day)	$49
CDFRM[2]	Cost of farm decontamination for various levels of decontamination ($/hectare)	$1,169 & $2,598
CDNFRM[2]	Cost of non-farm decontamination per resident person for various levels of decontamination ($/person)	$6,236 & $16,630
DLBCST[2]	Average cost of decontamination labor ($/man-year)	$72,756
VALWF[2]	Value of farm wealth ($/hectare)	$6,957
VALWNF[2]	Value of non-farm wealth average in US ($/person)	$181,881

(1) DPRATE and DSRATE are based on MACCS2 Users Manual (Reference 28)

(2) Calc 17676-0002 "Beaver Valley Power Station - MACCS2 Input Data".

3.4.3 Nuclide Release

The equilibrium core inventory was assumed at the end of a fuel cycle with fuel from three different fuel cycles in equal proportions. It was originally developed using ORIGEN-S as described in the BVPS Containment Conversion Licensing Report (Reference 31).

The following table provides the inventory of the core at shutdown used in this analysis. This information is from Reference 30, Section 5.2.3.3

Table 3.4.3-1 Core Inventory

Nuclide	Core Inventory (Curies)
Ag-111	5.05E+6
Ag-112	2.28E+6
Am-241	1.17E+4
Am-242	7.04E+6
Am-244	1.89E+7
Ba-137m	9.35E+6
Ba-139	1.41E+8
Ba-140	1.42E+8
Br-82	3.02E+5
Br-83	9.37E+6
Ce-141	1.30E+8
Ce-143	1.21E+8
Ce-144	9.82E+7
Cm-242	2.42E+6
Cm-244	5.97E+5
Cs-134	1.57E+7
Cs-134m	3.69E+6
Cs-135m	4.39E+6
Cs-136	4.97E+6
Cs-137	9.81E+6
Cs-138	1.48E+8
Eu-156	2.29E+7
Eu-157	2.41E+6
H-3	4.36E+4
I-129	2.86E+0
I-130	2.07E+6
I-131	7.78E+7
I-132	1.14E+8
I-133	1.60E+8
I-134	1.77E+8
I-135	1.52E+8
Kr-83m	9.46E+6
Kr-85	8.27E+5
Kr-85m	1.95E+7
Kr-87	3.91E+7
Kr-88	5.43E+7
La-140	1.46E+8

Table 3.4.3-1 Core Inventory (Cont.)

Nuclide	Core Inventory (Curies)
La-141	1.29E+8
La-142	1.26E+8
La-143	1.20E+8
Mo-101	1.33E+8
Mo-99	1.45E+8
Nb-95	1.34E+8
Nb-95m	1.52E+6
Nb-97	1.27E+8
Nb-97m	1.19E+8
Nd-147	5.22E+7
Nd-149	3.02E+7
Nd-151	1.58E+7
Np-238	3.98E+7
Np-239	1.66E+9
Np-240	4.32E+6
Pd-109	3.26E+7
Pm-147	1.38E+7
Pm-148	1.41E+7
Pm-148m	2.37E+6
Pm-149	4.82E+7
Pm-151	1.60E+7
Pr-142	5.57E+6
Pr-143	1.18E+8
Pr-144	9.89E+7
Pr-144m	1.38E+6
Pr-147	5.18E+7
Pu-238	3.40E+5
Pu-239	2.86E+4
Pu-240	3.87E+4
Pu-241	1.13E+7
Pu-242	2.01E+2
Pu-243	4.23E+7
Rb-86	1.69E+5
Rb-88	5.57E+7
Rb-89	7.26E+7
Rh-103m	1.26E+8
Rh-105	8.16E+7
Rh-106	5.13E+7

Table 3.4.3-1 Core Inventory (Cont.)

Nuclide	Core Inventory (Curies)
Ru-103	1.26E+8
Ru-105	8.90E+7
Ru-106	4.63E+7
Sb-127	6.92E+6
Sb-129	2.52E+7
Sb-130	8.37E+6
Sb-131	6.09E+7
Se-83	4.42E+6
Sm-153	4.02E+7
Sm-155	3.11E+6
Sm-156	1.93E+6
Sn-127	2.78E+6
Sr-89	7.61E+7
Sr-90	7.21E+6
Sr-91	9.50E+7
Sr-92	1.01E+8
Tc-101	1.33E+8
Tc-104	1.05E+8
Tc-99m	1.29E+8
Te-127	6.81E+6
Te-127m	1.13E+6
Te-129	2.40E+7
Te-129m	4.87E+6
Te-131	6.54E+7
Te-131m	1.57E+7
Te-132	1.12E+8
Te-133	8.66E+7
Te-133m	7.12E+7
Te-134	1.41E+8
U-239	1.66E+9
Xe-131m	1.08E+6
Xe-133	1.60E+8
Xe-133m	5.05E+6
Xe-135	4.84E+7
Xe-135m	3.36E+7
Xe-138	1.36E+8

Table 3.4.3-1 Core Inventory (Cont.)

Nuclide	Core Inventory (Curies)
Y-90	7.49E+6
Y-91	9.87E+7
Y-91m	5.51E+7
Y-92	1.02E+8
Y-93	7.73E+7
Y-94	1.23E+8
Y-95	1.28E+8
Zr-95	1.33E+8
Zr-97	1.26E+8

Table 3.4.3-2 provides a description of the release characteristics evaluated in this analysis.

Table 3.4.3-2 Release Descriptions

Release Category	Representative Bins	MACCS2 Run Code	Plume Number	Energy Level (cal/sec)	Energy Level (W)	Release Height (m)	Time of Release (hr)	Duration (hr)	Alarm Delay (hr)
Variable			NUMREL		PLHEAT	PLHITE	PDELAY	PLUDUR	OALARM
INTACT	BV21	A	1	454	1.90E+03	43.7	4	4	4
INTACT	BV21	A	2	262.84	1.10E+03	43.7	8	20	4
VSEQ-ECF	BV19	B	1	3.75E+07	1.57E+08	3.2	2	0.5	1
SGTR-ECF	BV18	C	1	8.48E+07	3.55E+08	26.82	8	0.5	1
DCH-ECF	BV1, BV3	D	1	6.59E+07	2.76E+08	43.7	3	4	1
VSEQ-SECF	BV20	E	1	1.00E+06	4.19E+06	3.2	3	1	1
LOCI-SECF	BV7	F	1	2.15E+06	9.00E+06	12	1.5	0.5	1
LOCI-SECF	BV7	F	2	1.12E+06	4.69E+06	12	2	9.5	1
BV5-SECF	BV5	K	1	2.15E+06	9.00E+06	43.7	1.5	0.5	1
BV5-SECF	BV5	K	2	1.12E+06	4.69E+06	43.7	2	9.5	1
Large-Late	BV10, BV12	G	1	6.59E+07	2.76E+08	43.7	10	0.5	4
Large-Late	BV10, BV12	G	2	1.27E+07	5.32E+07	43.7	10.5	3	4
Small-Late	BV13, BV15	H	1	1.31E+07	5.49E+07	43.7	25	0.5	4
Small-Late	BV13, BV15	H	2	2.63E+06	1.10E+07	43.7	25.5	9.5	4
H2 Burn-Late	BV9	I	1	6.59E+07	2.76E+08	43.7	10	0.5	4
H2 Burn-Late	BV9	I	2	1.27E+07	5.32E+07	43.7	10.5	3.5	4
BMMT-Late	BV17	J	1	6.59E+07	2.76E+08	0	24	1	4

3.4.4 Emergency Response

A reactor scram signal begins each evaluated accident sequence. A General Emergency is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public. Therefore, the timing of the General Emergency declaration is sequence specific and alarms range from 1 to 4 hours for the release sequences evaluated.

The MACCS2 User's Guide input parameters of 95 percent of the population within 10 miles of the plant [Emergency Planning Zone (EPZ)] evacuating and 5 percent not evacuating were employed. These values have been used in similar studies (e.g., Hatch, Calvert Cliffs, (SNOC 2000) and (BGE 1998)) and are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the EPZ.

The evacuation speed was calculated by comparing the travel time estimates to the travel distances required. The Aliquippa/Hopewell area has the greatest population density in the EPZ, requires the longest evacuation time, and is only a few miles from the edge of the EPZ. It follows that the slowest and most conservative evacuation speeds would occur in this area. Based on the published evacuation routes and the population distribution in the area, a typical travel distance to the edge of the EPZ from this area is approximately 3 miles. Using the worst case evacuation time (inclement weather and persons without transportation) of 6¼ hours an average evacuation speed of 0.2 m/s was determined.

Three evacuation sensitivity cases were also performed to determine the impact of evacuation assumptions. One sensitivity case reduced the evacuation speed by a factor of four (0.05 m/sec) and the second increased the speed to 2.24 m/s (5 mph). The third sensitivity case assumed a factor of 1.5 increase in the alarm time, thus delaying the commencement of physical evacuation. The results are discussed in Section 8.

3.4.5 Meteorological Data

Each year of meteorological data consists of 8,760 weather data sets of hourly recordings of wind direction, wind speed, atmospheric stability, and accumulated precipitation. The data were from the Beaver Valley Power Station site weather facility for the years 2001, 2002, 2003, 2004, and 2005. MACCS2 does not permit missing data, so bad or missing data were filled in with National Oceanic and Atmospheric Administration (NOAA) data from the Pittsburgh International Airport (nearest most complete source of data) obtained from the NOAA Internet website. The approach used in this analysis was to perform MACCS2 analyses for each of the years for which meteorological data was gathered and combine the results after the MACCS2 analyses rather than before. Due to the consideration of five years of weather data, it is assumed that the average result from the analysis would be considered typical and representative. No one year was found to be conservative with respect to all release sequences.

3.5 SEVERE ACCIDENT RISK RESULTS

Using the MACCS2 code, the dose and economic costs associated with a severe accident at Beaver Valley were calculated for each of the years for which meteorological data was gathered. This information is provided below in Table 3.5-1 and Table 3.5-2, respectively. The average value of the yearly result for each release category was used in the remainder of the analysis to represent the dose and cost for each of the specific release categories.

Table 3.5-1 Total L-EFFECTIVE LIFE Dose in Sieverts

Release Category	MACCS2 Run Code	BVPS Composite Weather Sensitivity Results					
		2001	2002	2003	2004	2005	Average
INTACT	A	8	7	8	7	7	8
ECF							
VSEQ	B	50,400	47,200	51,000	53,600	40,800	48,600
SGTR	C	44,500	41,400	43,800	46,500	37,000	42,640
DCH	D	86,800	84,800	86,600	76,400	77,600	82,440
SECF							
VSEQ	E	50,500	48,000	47,800	46,900	44,800	47,600
LOCI	F	35,200	35,500	33,200	34,000	36,400	34,860
BV5	K	43,800	39,800	41,300	41,000	42,700	41,720
LATE							
Large	G	1,530	1,440	1,780	1,600	1,450	1,560
Small	H	20,200	19,200	18,800	18,600	20,500	19,460
H2 Burn	I	19,300	17,200	17,600	16,300	17,900	17,660
BMMT	J	7,680	7,250	7,200	7,990	6,990	7,422

Table 3.5-2 Total Economic Costs in Dollars

Release Category	MACCS2 Run Code	BVPS Composite Weather Sensitivity Results					
		2001	2002	2003	2004	2005	Average
INTACT	A	6.400E+03	5.600E+03	5.590E+03	1.000E+04	7.510E+03	7.020E+03
ECF							
VSEQ	B	3.530E+10	3.260E+10	3.100E+10	3.350E+10	3.390E+10	3.326E+10
SGTR	C	4.280E+10	3.790E+10	3.580E+10	4.080E+10	3.840E+10	3.914E+10
DCH	D	4.800E+10	5.010E+10	5.010E+10	4.400E+10	5.000E+10	4.844E+10
SECF							
SGTR	E	2.540E+10	2.560E+10	2.690E+10	2.440E+10	2.920E+10	2.630E+10
LOCI	F	2.650E+10	2.520E+10	2.570E+10	2.460E+10	2.840E+10	2.608E+10
BV5	K	1.130E+10	1.070E+10	1.190E+10	1.050E+10	1.240E+10	1.136E+10
LATE							
Large	G	1.180E+08	1.260E+08	1.430E+08	1.590E+08	1.310E+08	1.354E+08
Small	H	1.090E+10	1.010E+10	1.150E+10	1.040E+10	1.170E+10	1.092E+10
H2 Burn	I	6.670E+09	6.220E+09	6.460E+09	5.600E+09	5.900E+09	6.170E+09
BMMT	J	4.380E+09	4.360E+09	5.480E+09	4.450E+09	4.700E+09	4.674E+09

3.6 MAJOR PRA MODELING DIFFERENCES BETWEEN BVPS UNIT 1 AND UNIT 2

Listed below are some major design differences between the BVPS Units that are accounted for in the PRA models. In addition, key differences in the BVPS PRA models were also previously docketed in Attachment B of the following letter.

- Pearce/USNRC, Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66 and BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests Nos. 306 and 176, dated October 29, 2004, Serial L-04-141.

1. Unit 1 has an additional feedwater pump (Dedicated AFW Pump) powered off the ERF diesel generator, which can be used during an SBO. This pump can provide secondary heat removal even if the SG are water solid, so it is not dependant on battery life. Unit 2 only has the Turbine-Driven AFW Pump, which fail if the SG goes water solid, so it is dependent on battery life during SBO conditions. Plant specific SBO MAAP analyses show that with the DAFW pump, as long as the RCP seal LOCA is initially less than 182 gpm and operators cooldown and depressurize the RCS, Unit 1 will not melt or uncover the core during a 48 hour period following the SBO. At Unit 2, this is not the case, and the core will uncover and melt during a 48 hour period following the SBO.

2. The Unit 1 Emergency DC Battery Rooms are constructed with concrete block walls, which have limited seismic capacity. At Unit 2 the Emergency DC Battery Rooms are constructed with reinforced concrete walls that have significant seismic capacity.

3. At Unit 1 the steam generators were replaced during 1RO17 and therefore have about half of the SGTR initiating event frequency of the Unit 2 value (2.09E-03 vs. 4.82E-03).

4. The Unit 2 RWST volume is about twice the size of the Unit 1 volume (~ 860,000 gal vs. ~440,000 gal).

5. At Unit 1 the atmospheric steam dump valves have a higher capacity than Unit 2 (294,400 lbs/hr vs. 235,000 lbs/hr) and therefore the RCS cooldown and depressurization using the secondary heat removal system success criteria is different. Unit 1 only requires 1 ASDV and feedwater to the associated SG, while Unit 2 requires 2 ASDVs with feedwater to both associated SGs.

6. Unit 2 normally has two Service Water pumps in service, while Unit 1 normally only has one River Water pump in service. Therefore, since the success criteria for both Units is one River Water/Service Water pump, there is a lower system failure probability at Unit 2 due to not having to start a standby pump given the failure of a running pump.

4 COST OF SEVERE ACCIDENT RISK / MAXIMUM BENEFIT

Cost/benefit evaluation of SAMAs is based upon the cost of implementation of a SAMA compared to the averted onsite and offsite costs resulting from the implementation of that SAMA. The methodology used for this evaluation was based upon the NRC's guidance for the performance of cost-benefit analyses (Reference 20). This guidance involves determining the net value for each SAMA according to the following formula:

Net Value = (APE + AOC + AOE + AOSC) – COE

where APE = present value of averted public exposure ($),
AOC = present value of averted offsite property damage costs ($),
AOE = present value of averted occupational exposure ($),
AOSC = present value of averted onsite costs ($)
COE = cost of enhancement ($).

If the net value of a SAMA is negative, the cost of implementing the SAMA is larger than the benefit associated with the SAMA and is not considered beneficial. The derivation of each of these costs is described in below.

The following specific values were used for various terms in the analyses:

Present Worth

The present worth was determined by:

$$PW = \frac{1 - e^{-rt}}{r}$$

Where:

r is the **discount rate = 7%** (assumed throughout these analyses)
t is the **duration of the license renewal = 20 years**
PW is the present worth of a string of annual payments = **10.76**

Dollars per REM

The conversion factor used for assigning a monetary value to on-site and off-site exposures was **$2,000/person-rem averted**. This is consistent with the NRC's regulatory analysis guidelines presented in and used throughout NUREG/BR-0184, Reference 20.

On-site Person REM per Accident

The occupational exposure associated with severe accidents was assumed to be **23,300 person-rem/accident.** This value includes a short-term component of 3,300 person-rem/accident and a long-term component of 20,000 person-rem/accident. These estimates are consistent with the "best estimate" values presented in Section 5.7.3 of Reference 20. In the cost/benefit analyses, the accident-related on-site exposures were calculated using the best estimate exposure components applied over the on-site cleanup period.

On-site Cleanup Period

In the cost/benefit analyses, the accident-related on-site exposures were calculated over a **10-year cleanup period**.

Present Worth On-site Cleanup Cost per Accident

The estimated cleanup cost for severe accidents was assumed to be **$1.5E+09/accident** (undiscounted). This value was derived by the NRC in Reference 20, Section 5.7.6.1, Cleanup and Decontamination. This cost is the sum of equal annual costs over a 10-year cleanup period. At a 7% discount rate, the present value of this stream of costs is **$1.1E+09**.

4.1 OFF-SITE EXPOSURE COST

Accident-Related Off-Site Dose Costs

Offsite doses were determined using the MACCS2 model developed for BVPS-1. Costs associated with these doses were calculated using the following equation:

$$APE = \left(F_S D_{P_S} - F_A D_{P_A}\right) R \frac{1 - e^{-rt_f}}{r} \qquad (1)$$

where:

APE = monetary value of accident risk avoided due to population doses, after discounting

R = monetary equivalent of unit dose, ($/person-rem)

F = accident frequency (events/yr)
D_P = population dose factor (person-rems/event)
S = status quo (current conditions)
A = after implementation of proposed action
r = real discount rate
t_f = analysis period (years).

Using the values for r, t_f, and R given above:

$$W_P = (\$2.15E + 4)\left(F_S D_{P_S} - F_A D_{P_A}\right)$$

4.2 OFF-SITE ECONOMIC COST

Accident-Related Off-Site Property Damage Costs

Offsite damage was determined using the MACCS2 model developed for BVPS-1. Costs associated with these damages were calculated using the following equation:

$$AOC = \left(F_S P_{D_S} - F_A P_{D_A}\right)\frac{1-e^{-rt_f}}{r}$$

where:

AOC = monetary value of accident risk avoided due to offsite property damage, after discounting
F = accident frequency (events/yr)
P_D = offsite property loss factor (dollars/event)
r = real discount rate
t_f = analysis period (years).

4.3 ON-SITE EXPOSURE COST

Methods for Calculating Averted Costs Associated with Onsite Accident Dose Costs

a) **Immediate Doses** (at time of accident and for immediate management of emergency)

For the case where the plant is in operation, the equations in Reference 20 can be expressed as:

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

where:

W_{IO} = monetary value of accident risk avoided due to immediate doses, after discounting
R = monetary equivalent of unit dose, ($/person-rem)
F = accident frequency (events/yr)
D_{IO} = immediate occupational dose (person-rems/event)
S = status quo (current conditions)
A = after implementation of proposed action
r = real discount rate
t_f = analysis period (years).

The values used are:
R = $2000/person rem
r = .07
D_{IO} = 3,300 person-rems /accident (best estimate)

The license extension time of 20 years is used for t_f.

For the basis discount rate, assuming F_A is zero, the <u>best estimate</u> of the limiting savings is

$$
\begin{aligned}
W_{IO} &= \left(F_S D_{IO_S}\right) R \frac{1-e^{-rt_f}}{r} \\
&= 3300 * F * \$2000 * \frac{1-e^{-.07*20}}{.07} \\
&= F * \$6{,}600{,}000 * 10.763 \\
&= F \; * \; \$0.71E \;\; + 8 \;, (\$).
\end{aligned}
$$

b) **<u>Long-Term Doses</u>** (process of cleanup and refurbishment or decontamination)

For the case where the plant is in operation, the equations in Reference 20 can be expressed as:

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

where:

W_{IO} = monetary value of accident risk avoided long term doses, after discounting, \$

m = years over which long-term doses accrue.

The values used are:

R = \$2000/person rem
r = .07
D_{LTO} = 20,000 person-rem /accident (best estimate)
m = “as long as 10 years”

The license extension period of 20 years is used for t_f.

For the discount rate of 7%, assuming F_A is zero, the <u>best estimate</u> of the limiting savings is

$$
\begin{aligned}
W_{LTO} &= \left(F_S D_{LTO_S}\right) R * \frac{1-e^{-rt_f}}{r} * \frac{1-e^{-rm}}{rm} \\
&= \left(F_S 20000\right) \$2000 * \frac{1-e^{-.07*20}}{.07} * \frac{1-e^{-.07*10}}{.07*10} \\
&= F_S * \$40{,}000{,}000 * 10.763 * 0.719 \\
&= F_S * \$3.10E + 8, (\$).
\end{aligned}
$$

c) **<u>Total Accident-Related Occupational (On-site) Exposures</u>**

Combining equations (1) and (2) above, using delta (Δ) to signify the difference in accident frequency resulting from the proposed actions, and using the above numerical values, the long term accident related on-site (occupational) exposure avoided (AOE) is:

Best Estimate:

$$AOE = W_{IO} + W_{LTO} = F * \$(0.71 + 3.1)E + 8 = F * \$3.81E + 8\ (\$)$$

4.4 ON-SITE ECONOMIC COST

Methods for Calculation of Averted Costs Associated with Accident-Related On-Site Property Damage

a) **Cleanup/Decontamination**

Reference 20 assumes a total cleanup/decontamination cost of $1.5E+9 as a reasonable estimate and this same value was adopted for these analyses. Considering a 10-year cleanup period, the present value of this cost is:

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

Where

PV_{CD}	=	Present value of the cost of cleanup/decontamination.
C_{CD}	=	Total cost of the cleanup/decontamination effort.
m	=	Cleanup period.
r	=	Discount rate.

Based upon the values previously assumed:

$$PV_{CD} = \left(\frac{\$1.5E + 9}{10}\right)\left(\frac{1 - e^{-.07*10}}{.07}\right)$$

$$PV_{CD} = \$1.079E + 9$$

This cost is integrated over the term of the proposed license extension as follows

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

Based upon the values previously assumed:

$$U_{CD} = \$1.079E + 9\ [10.763]$$

$$U_{CD} = \$1.161E+10$$

b) **Replacement Power Costs**

Replacement power costs, U_{RP}, are an additional contributor to onsite costs. These are calculated in accordance with NUREG/BR-0184, Section 5.6.7.2.[1] Since replacement power will be needed for that time period following a severe accident, for the remainder of the expected generating plant life, long-term power replacement calculations have been used. The calculations are based on the 910 MWe reference plant, and are appropriately scaled for the 984 MWe BVPS-1. The present value of replacement power is calculated as follows:

$$PV_{RP} = \left(\frac{(\$1.2E+8)\dfrac{(Ratepwr)}{(910MWe)}}{r} \right) \left(1 - e^{-rt_f}\right)^2$$

Where

PV_{RP}	=	Present value of the cost of replacement power for a single event.
	=	
t_f	=	Analysis period (years).
r	=	Discount rate.
Ratepwr	=	Rated power of the unit

The $1.2E+8 value has no intrinsic meaning but is a substitute for a string of non-constant replacement power costs that occur over the lifetime of a "generic" reactor after an event (from Reference 20). This equation was developed per NUREG/BR-0184 for discount rates between 5% and 10% only.

For discount rates between 1% and 5%, Reference 20 indicates that a linear interpolation is appropriate between present values of $1.2E+9 at 5% and $1.6E+9 at 1%. So for discount rates in this range the following equation was used to perform this linear interpolation.

$$PV_{RP} = \left\{ (\$1.6E+9) - \left(\frac{[(\$1.6E+9) - (\$1.2E+9)]}{[5\% - 1\%]} * [r_s - 1\%] \right) \right\} * \left\{ \frac{Ratepwr}{910MWe} \right\}$$

Where

r_s	=	Discount rate (small), between 1% and 5%.
Ratepwr	=	Rated power of the unit

[1] The section number for Section 5.6.7.2 apparently contains a typographical error. This section is a subsection of 5.7.6 and follows 5.7.6.1. However, the section number as it appears in the NUREG will be used in this document.

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

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

Where

U_{RP} = Present value of the cost of replacement power over the life of the facility.

Again, this equation is only applicable in the range of discount rates from 5% to 10%. NUREG/BR-0184 states that for lower discount rates, linear interpolations for U_{RP} are recommended between \$1.9E+10 at 1% and \$1.2E+10 at 5%. The following equation was used to perform this linear interpolations:

$$U_{RP} = \left\{(\$1.9E+10) - \left(\frac{[(\$1.9E+10) - (\$1.2E+10)]}{[5\% - 1\%]} * [r_s - 1\%]\right)\right\} * \left\{\frac{Ratepwr}{910MWe}\right\}$$

Where

r_s = Discount rate (small), between 1% and 5%.

Ratepwr = Rated power of the unit

c) **Repair and Refurbishment**

It is assumed that the plant would not be repaired/refurbished; therefore, there is not contribution to averted onsite costs from this source.

d) **Total Onsite Property Damage Costs**

The net present value of averted onsite damage costs is, therefore:

$$AOSC = F * (U_{CD} + U_{RP})$$

Where F = Annual frequency of the event.

4.5 TOTAL COST OF SEVERE ACCIDENT RISK / MAXIMUM BENEFIT

Cost/benefit evaluation of the maximum benefit is baseline risk of the plant converted dollars by summing the contributors to cost.

Maximum Benefit Value = (APE + AOC + AOE + AOSC)

where APE = present value of averted public exposure (\$),

AOC = present value of averted offsite property damage costs (\$),

AOE = present value of averted occupational exposure ($),
AOSC = present value of averted onsite costs ($)

For Beaver Valley Unit 1, this value is $5,129,572 as shown below.

Parameter	Unit 1 Present Dollar Value ($)
Averted Public Exposure	$1,246,705
Averted offsite costs	$3,483,791
Averted occupational exposure	$7,402
Averted onsite costs	$391,674
Total	$5,129,572

The costs are dominated by the early small and late small release categories. The dominant accident sequences that result in these release categories are largely the result of fire and seismic initiating events. These initiating events are explicitly modeled in the PRA.

5 SAMA IDENTIFICATION

A list of SAMA candidates was developed by reviewing the major contributors to CDF and population dose based on the plant-specific risk assessment and the standard PWR list of enhancements from Reference 24 (NEI 05-01). This section discusses the SAMA selection process and its results.

5.1 PRA IMPORTANCE

The top core damage sequences and the components/systems having the greatest potential for risk reduction were examined to determine whether additional SAMAs could be identified from these sources.

Use of Importance Measures
Risk reduction worth (RRW) of the components in the baseline model was used to identify those basic events that could have a significant potential for reducing risk. Components with risk reduction worth (RRW) >1.005 were identified as the most important components. A similar review was performed on a system basis. The components and systems were reviewed to ensure that each component and system is covered by an existing SAMA item or added to the list if not.

Use of the Top Sequences
The top sequences leading to core melt were reviewed. A key result is that no single PRA sequence makes up a large fraction of the core damage frequency. The sequences were reviewed

to ensure that initiators and failures identified in the sequences were either covered by existing SAMAs or added to the list of plant specific SAMAs.

5.2 PLANT IPE

The Beaver Valley Unit 1 PRA identified some potential vulnerabilities. Corresponding enhancements have been considered. As noted in the IPE, large fractions of the CDF were associated with RCP seal LOCA and station blackout. Other major contributors were containment bypass/isolation failure, loss of switchgear HVAC and transients without scram.

These accident categories are not always mutually exclusive. One of the top ranked sequences illustrates this clearly. A loss of offsite power will challenge the onsite emergency power system. Failure of both emergency diesels would result in a station blackout. The consequential loss of seal injection and component cooling water to the reactor coolant pumps (RCP) thermal barrier could eventually lead to a RCP seal LOCA. Station blackout and RCP seal LOCA are both conditions of this scenario that can result in core uncovery and damage.

In order to determine vulnerabilities, the major accident categories were evaluated along with the top-ranking sequences contributing to CDF.

The Beaver Valley Unit 1 potential enhancements are listed in Table 5.2-1.

Table 5.2-1. Beaver Valley Unit 1 IPE Potential Enhancements

Vulnerability	Procedure or Design Enhancement	Impact of Enhancement	CDF Importance		Status
			Percent of CDF	Risk * Reduction Worth	
AC Power Generation Capability for Station Blackout	Provide Beaver Valley Units 1 and 2 with 4,160 V Bus Crosstie Capability	Adds a success path for blackout on Unit 2 when both Unit 1 diesel generators work, and vice versa	30.4	0.8647	Intent Met . SAMAs 9 and 154
Reactor Trip breaker failure	Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	19.9	0.7949	SAMA 155, Analysis shows that actions outside the control room cannot be performed quickly enough. PRA updates have reduced the contribution from ATWS events.
Pressurizer PORV block valve alignment	Operate plant with all PORV block valves open or provide procedures to open block valves when Main Feedwater is lost.	Increased pressure relief capacity to prevent reactor vessel rupture during ATWS.	15.6	0.8900	Intent Met. SAMA 156; Normal operational alignment has all 3 block valves open. The configuration risk management program limits the amount of time the PORV block valves can remain closed.
Loss of Emergency Switchgear Room HVAC	Enhanced Loss of HVAC Procedures	Confidence that operators will prevent thermal damage to switchgear	15.5	0.8708	Intent Met. SAMA 157, further analysis shows that there is a long time for installation of temporary ventilation.
RCP Seal Cooling for Station Blackout	Potential modifications under review	Reduced frequency of RCP seal LOCA resulting from blackout	13.8	**	Intent Met, SAMA 158
Battery Capacity for steam generator level instruments for station blackout	Enhance procedures on shedding loads or using portable battery chargers. One train of the battery chargers will be powered from the site operable emergency diesel generator once the Station Blackout Unit crosstie modification is complete.	Extended operating time for steam generator level instruments for loss of all AC power scenarios	10.7	0.8933	Intent Met. SAMA 159
Pressurizer PORV sticking open after loss of offsite power	Eliminate challenge by defeating the 100% load rejection capability	Reduced frequency of pressurizer PORV sticking open	2.0	0.9808	SAMA 160, turbine trip above 30% causes reactor trip.
Fast 4,160 V Bus Transfer Failure	Explicit Procedure and Training on breaker repair or change out	Reduced frequency that breaker failures will challenge diesel generators	1.5	0.9855	Intent Met , SAMA 161

Note: * The risk reduction worth is the factor decrease in CDF that would be realized if the failure probability of the affected system were decreased to 0.0 (i.e., guaranteed success).
** Included in the AC power generation capability for station blackout risk reduction worth value.

5.3 PLANT IPEEE

Potential improvements to reduce the risk in dominant fire zones and to reduce seismic risk and risk from other external events were evaluated in the Beaver Valley Unit 1 IPEEE. The list of candidate improvements and their status is documented in the IPEEE and reproduced in Table 3.1.2-1 in this report.

5.4 INDUSTRY SAMA CANDIDATES

The generic PWR enhancement list from Table 14 of Reference 24 was included in the list of Phase I SAMA candidates to assure adequate consideration of potential enhancements identified by other industry studies.

5.5 PLANT STAFF INPUT TO SAMA CANDIDATES

The Beaver Valley plant staff provided plant specific items that were included in the evaluation. These are identified in the list of SAMA candidates by their source.

5.6 LIST OF PHASE I SAMA CANDIDATES

Table 5.6-1 provides the combined list of potential SAMA candidates considered in the Beaver Valley Unit 1 SAMA analysis. From this table it can be seen that 189 SAMA candidates were identified for consideration.

Table 5.6-1 List of SAMA Candidates

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
1	Provide additional DC battery capacity.	Extended DC power availability during an SBO.	AC/DC	1, C
2	Replace lead-acid batteries with fuel cells.	Extended DC power availability during an SBO.	AC/DC	1
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	AC/DC	1, C
4	Improve DC bus load shedding.	Extended DC power availability during an SBO.	AC/DC	1
5	Provide DC bus cross-ties.	Improved availability of DC power system.	AC/DC	1
6	Provide additional DC power to the 120/240V vital AC system.	Increased availability of the 120 V vital AC bus.	AC/DC	1
7	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.	AC/DC	1
8	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.	AC/DC	1
9	Provide an additional diesel generator.	Increased availability of on-site emergency AC power.	AC/DC	1
10	Revise procedure to allow bypass of diesel generator trips.	Extended diesel generator operation.	AC/DC	1
11	Improve 4.16-kV bus cross-tie ability.	Increased availability of on-site AC power.	AC/DC	1, A
12	Create AC power cross-tie capability with other unit (multi-unit site)	Increased availability of on-site AC power.	AC/DC	1, A
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	AC/DC	1
14	Install a gas turbine generator.	Increased availability of on-site AC power.	AC/DC	1
15	Install tornado protection on gas turbine generator.	Increased availability of on-site AC power.	AC/DC	1
16	Improve uninterruptible power supplies.	Increased availability of power supplies supporting front-line equipment.	AC/DC	1
17	Create a cross-tie for diesel fuel oil (multi-unit site).	Increased diesel generator availability.	AC/DC	1
18	Develop procedures for replenishing diesel fuel oil.	Increased diesel generator availability.	AC/DC	1
19	Use fire water system as a backup source for diesel cooling.	Increased diesel generator availability.	AC/DC	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
20	Add a new backup source of diesel cooling.	Increased diesel generator availability.	AC/DC	1
21	Develop procedures to repair or replace failed 4 KV breakers.	Increased probability of recovery from failure of breakers that transfer 4.16 kV non-emergency buses from unit station service transformers.	AC/DC	1, A
22	In training, emphasize steps in recovery of off-site power after an SBO.	Reduced human error probability during off-site power recovery.	AC/DC	1
23	Develop a severe weather conditions procedure.	Improved off-site power recovery following external weather-related events.	AC/DC	1
24	Bury off-site power lines.	Improved off-site power reliability during severe weather.	AC/DC	1
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	Core Cooling	1
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	Core Cooling	1
27	Revise procedure to allow operators to inhibit automatic vessel depressurization in non-ATWS scenarios.	Extended HPCI and RCIC operation.	Core Cooling	1
28	Add a diverse low pressure injection system.	Improved injection capability.	Core Cooling	1
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	Core Cooling	1
30	Improve ECCS suction strainers.	Enhanced reliability of ECCS suction.	Core Cooling	1
31	Add the ability to manually align emergency core cooling system recirculation.	Enhanced reliability of ECCS suction.	Core Cooling	1
32	Add the ability to automatically align emergency core cooling system to recirculation mode upon refueling water storage tank depletion.	Enhanced reliability of ECCS suction.	Core Cooling	1
33	Provide hardware and procedure to refill the reactor water storage tank once it reaches a specified low level.	Extended reactor water storage tank capacity in the event of a steam generator tube rupture (or other LOCAs challenging RWST capacity) .	Core Cooling	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
34	Provide an in-containment reactor water storage tank.	Continuous source of water to the safety injection pumps during a LOCA event, since water released from a breach of the primary system collects in the in-containment reactor water storage tank, and thereby eliminates the need to realign the safety injection pumps for long-term post-LOCA recirculation.	Core Cooling	1
35	Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	Extended reactor water storage tank capacity.	Core Cooling	1
36	Emphasize timely recirculation alignment in operator training.	Reduced human error probability associated with recirculation failure.	Core Cooling	1
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	Core Cooling	1
38	Change the in-containment reactor water storage tank suction from four check valves to two check and two air-operated valves.	Reduced common mode failure of injection paths.	Core Cooling	1
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injections systems.	Core Cooling	1
40	Provide capability for remote, manual operation of secondary side pilot-operated relief valves in a station blackout.	Improved chance of successful operation during station blackout events in which high area temperatures may be encountered (no ventilation to main steam areas).	Core Cooling	1
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	Core Cooling	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
42	Make procedure changes for reactor coolant system depressurization.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	Core Cooling	1
43	Add redundant DC control power for SW pumps.	Increased availability of SW.	Cooling Water	1
44	Replace ECCS pump motors with air-cooled motors.	Elimination of ECCS dependency on component cooling system.	Cooling Water	1
45	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.	Cooling Water	1
46	Add a service water pump.	Increased availability of cooling water.	Cooling Water	1
47	Enhance the screen wash system.	Reduced potential for loss of SW due to clogging of screens.	Cooling Water	1
48	Cap downstream piping of normally closed component cooling water drain and vent valves.	Reduced frequency of loss of component cooling water initiating events, some of which can be attributed to catastrophic failure of one of the many single isolation valves.	Cooling Water	1
49	Enhance loss of component cooling water (or loss of service water) procedures to facilitate stopping the reactor coolant pumps.	Reduced potential for reactor coolant pump seal damage due to pump bearing failure.	Cooling Water	1
50	Enhance loss of component cooling water procedure to underscore the desirability of cooling down the reactor coolant system prior to seal LOCA.	Reduced probability of reactor coolant pump seal failure.	Cooling Water	1
51	Additional training on loss of component cooling water.	Improved success of operator actions after a loss of component cooling water.	Cooling Water	1
52	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	Reduced effect of loss of component cooling water by providing a means to maintain the charging pump seal injection following a loss of normal cooling water.	Cooling Water	1
53	On loss of essential raw cooling water, proceduralize shedding component cooling water loads to extend the component cooling water heat-up time.	Increased time before loss of component cooling water (and reactor coolant pump seal failure) during loss of essential raw cooling water sequences.	Cooling Water	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	Cooling Water	1
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	Cooling Water	1
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	Cooling Water	1
57	Use existing hydro test pump for reactor coolant pump seal injection.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout, unless an alternate power source is used..	Cooling Water	1
58	Install improved reactor coolant pump seals.	Reduced likelihood of reactor coolant pump seal LOCA.	Cooling Water	1
59	Install an additional component cooling water pump.	Reduced likelihood of loss of component cooling water leading to a reactor coolant pump seal LOCA.	Cooling Water	1
60	Prevent makeup pump flow diversion through the relief valves.	Reduced frequency of loss of reactor coolant pump seal cooling if spurious high pressure injection relief valve opening creates a flow diversion large enough to prevent reactor coolant pump seal injection.	Cooling Water	1
61	Change procedures to isolate reactor coolant pump seal return flow on loss of component cooling water, and provide (or enhance) guidance on loss of injection during seal LOCA.	Reduced frequency of core damage due to loss of seal cooling.	Cooling Water	1
62	Implement procedures to stagger high pressure safety injection pump use after a loss of service water.	Extended high pressure injection prior to overheating following a loss of service water.	Cooling Water	1
63	Use fire prevention system pumps as a backup seal injection and high pressure makeup source.	Reduced frequency of reactor coolant pump seal LOCA.	Cooling Water	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	Cooling Water	1
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	Feedwater/Condensate	1
66	Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	Increased availability of feedwater.	Feedwater/Condensate	1
67	Install an independent diesel for the condensate storage tank makeup pumps.	Extended inventory in CST during an SBO.	Feedwater/Condensate	1
68	Add a motor-driven feedwater pump.	Increased availability of feedwater.	Feedwater/Condensate	1
69	Install manual isolation valves around auxiliary feedwater turbine-driven steam admission valves.	Reduced dual turbine-driven pump maintenance unavailability.	Feedwater/Condensate	1
70	Install accumulators for turbine-driven auxiliary feedwater pump flow control valves.	Eliminates the need for local manual action to align nitrogen bottles for control air following a loss of off-site power.	Feedwater/Condensate	1
71	Install a new condensate storage tank (auxiliary feedwater storage tank).	Increased availability of the auxiliary feedwater system.	Feedwater/Condensate	1
72	Modify the turbine-driven auxiliary feedwater pump to be self-cooled.	Improved success probability during a station blackout.	Feedwater/Condensate	1
73	Proceduralize local manual operation of auxiliary feedwater system when control power is lost.	Extended auxiliary feedwater availability during a station blackout. Also provides a success path should auxiliary feedwater control power be lost in non-station blackout sequences.	Feedwater/Condensate	1
74	Provide hookup for portable generators to power the turbine-driven auxiliary feedwater pump after station batteries are depleted.	Extended auxiliary feedwater availability.	Feedwater/Condensate	1
75	Use fire water system as a backup for steam generator inventory.	Increased availability of steam generator water supply.	Feedwater/Condensate	1
76	Change failure position of condenser makeup valve if the condenser makeup valve fails open on loss of air or power.	Allows greater inventory for the auxiliary feedwater pumps by preventing condensate storage tank flow diversion to the condenser.	Feedwater/Condensate	1
77	Provide a passive, secondary-side heat-rejection loop consisting of a condenser and heat sink.	Reduced potential for core damage due to loss-of-feedwater events.	Feedwater/Condensate	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	Feedwater/Condensate	1
79	Replace existing pilot-operated relief valves with larger ones, such that only one is required for successful feed and bleed.	Increased probability of successful feed and bleed.	Feedwater/Condensate	1
80	Provide a redundant train or means of ventilation.	Increased availability of components dependent on room cooling.	HVAC	1
81	Add a diesel building high temperature alarm or redundant louver and thermostat.	Improved diagnosis of a loss of diesel building HVAC.	HVAC	1
82	Stage backup fans in switchgear rooms.	Increased availability of ventilation in the event of a loss of switchgear ventilation.	HVAC	1
83	Add a switchgear room high temperature alarm.	Improved diagnosis of a loss of switchgear HVAC.	HVAC	1
84	Create ability to switch emergency feedwater room fan power supply to station batteries in a station blackout.	Continued fan operation in a station blackout.	HVAC	1
85	Provide cross-unit connection of uninterruptible compressed air supply.	Increased ability to vent containment using the hardened vent.	IA/Nitrogen	1
86	Modify procedure to provide ability to align diesel power to more air compressors.	Increased availability of instrument air after a LOOP.	IA/Nitrogen	1
87	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 service water cooling.	IA/Nitrogen	1
88	Install nitrogen bottles as backup gas supply for safety relief valves.	Extended SRV operation time.	IA/Nitrogen	1
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	IA/Nitrogen	1
90	Create a reactor cavity flooding system.	Enhanced debris cool ability, reduced core concrete interaction, and increased fission product scrubbing.	Containment Phenomena	1
91	Install a passive containment spray system.	Improved containment spray capability.	Containment Phenomena	1
92	Use the fire water system as a backup source for the containment spray system.	Improved containment spray capability.	Containment Phenomena	1
93	Install an unfiltered, hardened containment vent.	Increased decay heat removal capability for non-ATWS events, without scrubbing released fission products.	Containment Phenomena	1
94	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.	Containment Phenomena	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
95	Enhance fire protection system and standby gas treatment system hardware and procedures.	Improved fission product scrubbing in severe accidents.	Containment Phenomena	1
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	Containment Phenomena	1
97	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.	Containment Phenomena	1
98	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.	Containment Phenomena	1
99	Strengthen primary/secondary containment (e.g., add ribbing to containment shell).	Reduced probability of containment over-pressurization.	Containment Phenomena	1
100	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.	Containment Phenomena	1
101	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.	Containment Phenomena	1
102	Construct a building to be connected to primary/secondary containment and maintained at a vacuum.	Reduced probability of containment over-pressurization.	Containment Phenomena	1
103	Institute simulator training for severe accident scenarios.	Improved arrest of core melt progress and prevention of containment failure.	Containment Phenomena	1
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	Containment Phenomena	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
105	Delay containment spray actuation after a large LOCA.	Extended reactor water storage tank availability.	Containment Phenomena	1
106	Install automatic containment spray pump header throttle valves.	Extended time over which water remains in the reactor water storage tank, when full containment spray flow is not needed.	Containment Phenomena	1
107	Install a redundant containment spray system.	Increased containment heat removal ability.	Containment Phenomena	1
108	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.	Containment Phenomena	1
109	Install a passive hydrogen control system.	Reduced hydrogen detonation potential.	Containment Phenomena	1
110	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.	Containment Phenomena	1
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	Containment Bypass	1
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	Containment Bypass	1
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	Containment Bypass	1
114	Install self-actuating containment isolation valves.	Reduced frequency of isolation failure.	Containment Bypass	1
115	Locate residual heat removal (RHR) inside containment	Reduced frequency of ISLOCA outside containment.	Containment Bypass	1
116	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.	Containment Bypass	1
117	Revise EOPs to improve ISLOCA identification.	Increased likelihood that LOCAs outside containment are identified as such. A plant had a scenario in which an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment.	Containment Bypass	1
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	Containment Bypass	1
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	Containment Bypass	1
120	Replace steam generators with a new design.	Reduced frequency of steam generator tube ruptures.	Containment Bypass	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
121	Increase the pressure capacity of the secondary side so that a steam generator tube rupture would not cause the relief valves to lift.	Eliminates release pathway to the environment following a steam generator tube rupture.	Containment Bypass	1
122	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture	Enhanced depressurization capabilities during steam generator tube rupture.	Containment Bypass	1
123	Proceduralize use of pressurizer vent valves during steam generator tube rupture sequences.	Backup method to using pressurizer sprays to reduce primary system pressure following a steam generator tube rupture.	Containment Bypass	1
124	Provide improved instrumentation to detect steam generator tube ruptures, such as Nitrogen-16 monitors).	Improved mitigation of steam generator tube ruptures.	Containment Bypass	1
125	Route the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove most of the fission products.	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1
126	Install a highly reliable (closed loop) steam generator shell-side heat removal system that relies on natural circulation and stored water sources	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1
127	Revise emergency operating procedures to direct isolation of a faulted steam generator.	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1
128	Direct steam generator flooding after a steam generator tube rupture, prior to core damage.	Improved scrubbing of steam generator tube rupture releases.	Containment Bypass	1
129	Vent main steam safety valves in containment.	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	ATWS	1
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	ATWS	1
132	Provide an additional control system for rod insertion (e.g., AMSAC).	Improved redundancy and reduced ATWS frequency.	ATWS	1
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	ATWS	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
134	Revise procedure to bypass MSIV isolation 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 human error probabilities.	ATWS	1
135	Revise procedure to allow override of low pressure core injection during an ATWS event.	Allows immediate control of low pressure core injection. On failure of high pressure core injection and condensate, some plants direct reactor depressurization followed by five minutes of automatic low pressure core injection.	ATWS	1
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	ATWS	1
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	ATWS	1
138	Improve inspection of rubber expansion joints on main condenser.	Reduced frequency of internal flooding due to failure of circulating water system expansion joints.	Internal Flooding	1
139	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	Prevents flood propagation.	Internal Flooding	1
140	Increase seismic ruggedness of plant components.	Increased availability of necessary plant equipment during and after seismic events.	Seismic Risk	1
141	Provide additional restraints for CO2 tanks.	Increased availability of fire protection given a seismic event.	Seismic Risk	1
142	Replace mercury switches in fire protection system.	Decreased probability of spurious fire suppression system actuation.	Fire Risk	1
143	Upgrade fire compartment barriers.	Decreased consequences of a fire.	Fire Risk	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
144	Install additional transfer and isolation switches.	Reduced number of spurious actuations during a fire.	Fire Risk	1
145	Enhance fire brigade awareness.	Decreased consequences of a fire.	Fire Risk	1
146	Enhance control of combustibles and ignition sources.	Decreased fire frequency and consequences.	Fire Risk	1
147	Install digital large break LOCA protection system.	Reduced probability of a large break LOCA (a leak before break).	Other	1
148	Enhance procedures to mitigate large break LOCA.	Reduced consequences of a large break LOCA.	Other	1
149	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.	Other	1
150	Improve maintenance procedures.	Improved prevention of core melt sequences by increasing reliability of important equipment.	Other	1
151	Increase training and operating experience feedback to improve operator response.	Improved likelihood of success of operator actions taken in response to abnormal conditions.	Other	1
152	Develop procedures for transportation and nearby facility accidents.	Reduced consequences of transportation and nearby facility accidents.	Other	1
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	Other	1
154	Provide Beaver Valley Units 1 and 2 with 4,160 V Bus Crosstie Capability	Adds a success path for blackout on Unit 2 when both Unit 1 diesel generators work, and vice versa	AC/DC	A
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	ATWS	A

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
156	Operate plant with all PORV block valves open or provide procedures to open block valves when Main Feedwater is lost.	Increased pressure relief capacity to prevent reactor vessel rupture during ATWS.	ATWS	A
157	Loss of Emergency Switchgear Room HVAC , Enhanced Loss of HVAC Procedures	Confidence that operators will prevent thermal damage to switchgear	HVAC	A
158	RCP Seal Cooling for Station Blackout, Potential modifications under review	Reduced frequency of RCP seal LOCA resulting from blackout	Cooling Water	A
159	Battery Capacity for steam generator level instruments for station blackout, Enhance procedures on shedding loads or using portable battery chargers. One train of the battery chargers will be powered from the site operable emergency diesel generator once the SBO unit cross-tie modification is complete.	Extended operating time for steam generator level instruments for less of all AC power scenarios	AC/DC	A
160	Pressurizer PORV sticking open after loss of offsite power, Eliminate challenge by defeating the 100% load rejection capability.	Reduced frequency of pressurizer PORV sticking open	Core Cooling	A
161	Fast 4,160 V Bus Transfer Failure, Explicit Procedure and Training on breaker repair or change out	Reduced frequency that breaker failures will challenge diesel generators	AC/DC	A
162	Provide a dedicated diesel driven fire water pump with supply tank to provide an additional source of water for SG tube coverage during SGTR events.	This would eliminate the LERF category and reduce all SGTR events to Small Early Releases.	Containment Bypass	C
163	Modify Loss of DC AOP to proceduralize the use of backup battery chargers.	Provide better reliability of the DC busses.	AC/DC	C
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	Containment Bypass	C
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	Cooling Water	C
166	Provide additional emergency 125V DC battery capability.	Better coping for long term station blackouts	AC/DC	C
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	Seismic Risk	C
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	Fire Risk	C
169	Improve operator performance. Operator starts Aux RW pump given offsite power is available.	One of top 10 operator actions, OPRWA1	Human Reliability	D

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
170	Improve operator performance. Operator starts portable fans & open doors in emergency switchgear room	One of top 10 operator actions, OPRWBV3	Human Reliability	D
171	Improve operator performance. Operator initiates Safety Injection	One of top 10 operator actions, OPROS6	Human Reliability	D
172	Improve operator performance. Operator initiates bleed and feed cooling given failure of prior actions to restore feedwater systems.	One of top 10 operator actions, OPROB2	Human Reliability	D
173	Improve operator performance. Operator initiates makeup of RWST	One of top 10 operator actions, OPRWM1	Human Reliability	D
174	Improve operator performance. Operator trips RCPs during loss of CCR.	One of top 10 operator actions, OPROC1	Human Reliability	D
175	Improve operator performance. Operator initiates depressurization of RCS given a general transient initiating event.	One of top 10 operator actions, OPROD2	Human Reliability	D
176	Improve operator performance. Operator initiates depressurization of RCS given a SGTR event.	One of top 10 operator actions, OPROD1	Human Reliability	D
177	Improve operator performance. Operator initiates cooldown and depressurization of RCS given a Small LOCA and failure of HHSI.	One of top 10 operator actions, OPRCD6	Human Reliability	D
178	Improve operator performance. Operator aligns hot leg recirculation.	One of top 10 operator actions, OPRLR1	Human Reliability	D
179	Emergency 125V DC battery room block walls Seismic concern from IPEEE.	Reevaluate block wall fragility, reinforce block walls, or shield batteries.	Seismic Risk	B
180	Reroute River Water pump power cable	IPEEE issue with CV-3 fire.	Fire Risk	B
181	Refine Emergency Switchgear room heatup analysis to provide additional time margin.	IPEEE fire issue for CS-1 fire, SW corner.	Fire Risk	B
182	Reroute CCR pump or HHSI suction MOV cables.	IPEEE fire issue for PA-1 fire.	Fire Risk	B
183	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for CS-1 fire, NE corner.	Fire Risk	B
184	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for NS-1 fire, south wall.	Fire Risk	B
185	Install Westinghouse RCP Shutdown seals to work with high temperature O-Rings.	Reduced seal LOCA probability	Cooling Water	F
186	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	Containment	E
187	Increase seismic ruggedness of the ERF Substation batteries. This applies to the battery rack only and not the entire structure.	Increased reliability of the ERF diesel following seismic events	Seismic Risk	F

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
188	Install a cross-tie between the Unit 1 and Unit 2 RWST.	Increased availability of the RWST for injection.	Core Cooling	E
189	Provide Diesel backed power for the fuel pool purification pumps and valves used for makeup to the RWST.	Increased availability of the RWST during loss of offsite power and station blackout events.	Core Cooling	E

Note 1: The source references are:

1 NEI 05-01 (Reference 24)
A IPE (Reference 2)
B IPEEE (Reference 3)
C Beaver Valley Power Station ELT 2004 Strategic Action Plan - Safe Plant Operations. (Reference 39)
D BV1REV4 PRA (Reference 27)
E NISYS-1092-C006 (Reference 37).
F Undocumented conversations/Interviews with site personnel.

6 PHASE I ANALYSIS

A preliminary screening of the complete list of SAMA candidates was performed to limit the number of SAMAs for which detailed analysis in Phase II was necessary. The screening criteria used in the Phase I analysis are described below.

- ***Screening Criterion A - Not Applicable***: If a SAMA candidate did not apply to the Beaver Valley Unit 1 plant design, it was not retained.
- ***Screening Criterion B - Already Implemented or Intent Met***: If a SAMA candidate had already been implemented at the Beaver Valley Unit 1 or the intent of the candidate is met, it was not retained.
- ***Screening Criterion C - Combined***: If a SAMA candidate was similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or plant-specific SAMA candidate, only the combined SAMA candidate was retained.
- ***Screening Criterion D - Excessive Implementation Cost***: If a SAMA required extensive changes that will obviously exceed the maximum benefit (Section 4.5), even without an implementation cost estimate, it was not retained.
- ***Screening Criterion E - Very Low Benefit***: If a SAMA from an industry document was related to a non-risk significant system for which change in reliability is known to have negligible impact on the risk profile, it was not retained. (No SAMAs were screened using this criterion.)

Table 6-1 presents the list of Phase I SAMA candidates and provides the disposition of each candidate along with the applicable screening criterion associated with each candidate. Those candidates that have not been screened by application of these criteria are evaluated further in the Phase II analysis (Section 7). It can be seen from this table that 126 SAMAs were screened from the analysis during Phase 1 and that 63 SAMAs passed into the next phase of the analysis.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
15	Install tornado protection on gas turbine generator.	Increased availability of on-site AC power.	Yes	A - Not Applicable	Not applicable. Plant does not have gas turbine generator.
27	Revise procedure to allow operators to inhibit automatic vessel depressurization in non-ATWS scenarios.	Extended HPCI and RCIC operation.	Yes	A - Not Applicable	Not applicable. Description of HPCI and RCIC use implies BWR item.
35	Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	Extended reactor water storage tank capacity.	Yes	A - Not Applicable	Per Expert Panel: LHI only used in LBLOCA sequences, throttling not considered. Long-term cooling is sump recirc.
38	Change the in-containment reactor water storage tank suction from four check valves to two check and two air-operated valves.	Reduced common mode failure of injection paths.	Yes	A - Not Applicable	Not Applicable. Beaver Valley suction of different design.
52	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	Reduced effect of loss of component cooling water by providing a means to maintain the charging pump seal injection following a loss of normal cooling water.	Yes	A - Not Applicable	Not Applicable per Expert Panel - Charging pumps seals do not require cooling.
57	Use existing hydro test pump for reactor coolant pump seal injection.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout, unless an alternate power source is used..	Yes	A - Not Applicable	Cannot be implemented due to design limitations. The pressure pulses from the positive displacement pump will damage the seal, leading to seal failure.
60	Prevent makeup pump flow diversion through the relief valves.	Reduced frequency of loss of reactor coolant pump seal cooling if spurious high pressure injection relief valve opening creates a flow diversion large enough to prevent reactor coolant pump seal injection.	Yes	A - Not Applicable	Expert Panel: No relief valves on applicable section of piping.
62	Implement procedures to stagger high pressure safety injection pump use after a loss of service water.	Extended high pressure injection prior to overheating following a loss of service water.	Yes	A - Not Applicable	Due to the estimated time of 12 minutes for pump failure following loss of lube oil cooling and the restricted start duty times of 45 minutes between starts this is not considered a viable option.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
63	Use fire prevention system pumps as a backup seal injection and high pressure makeup source.	Reduced frequency of reactor coolant pump seal LOCA.	Yes	A - Not Applicable	Not applicable. Fire pumps do not have sufficient discharge pressure for high pressure makeup source.
69	Install manual isolation valves around auxiliary feedwater turbine-driven steam admission valves.	Reduced dual turbine-driven pump maintenance unavailability.	Yes	A - Not Applicable	Not Applicable. Beaver Valley does not have dual turbine design.
76	Change failure position of condenser makeup valve if the condenser makeup valve fails open on loss of air or power.	Allows greater inventory for the auxiliary feedwater pumps by preventing condensate storage tank flow diversion to the condenser.	Yes	A - Not Applicable	Not applicable. Condenser makeup valve fails closed.
84	Create ability to switch emergency feedwater room fan power supply to station batteries in a station blackout.	Continued fan operation in a station blackout.	Yes	A - Not Applicable	TDAFW pump rated for high temp. No backup ventilation is needed.
105	Delay containment spray actuation after a large LOCA.	Extended reactor water storage tank availability.	Yes	A - Not Applicable	Delaying the containment spray actuation following a large LOCA, would potentially result in exceeding containment design pressure and/or temperature.
108	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.	Yes	A - Not Applicable	Hydrogen recombiners previously abandoned in-place.
109	Install a passive hydrogen control system.	Reduced hydrogen detonation potential.	Yes	A - Not Applicable	Hydrogen recombiners previously abandoned in-place.
134	Revise procedure to bypass MSIV isolation 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 human error probabilities.	Yes	A - Not Applicable	Expert Panel - Determined this is a BWR issue. Additionally, MSIVs cannot be opened once closed.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
135	Revise procedure to allow override of low pressure core injection during an ATWS event.	Allows immediate control of low pressure core injection. On failure of high pressure core injection and condensate, some plants direct reactor depressurization followed by five minutes of automatic low pressure core injection.	Yes	A - Not Applicable	Not applicable. This should be limited to BWR ATWS response.
139	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	Prevents flood propagation.	Yes	A - Not Applicable	No internal flooding sources of any risk significance identified.
140	Increase seismic ruggedness of plant components.	Increased availability of necessary plant equipment during and after seismic events.	Yes	A - Not Applicable	Specific identified items addressed in other SAMAs
141	Provide additional restraints for CO2 tanks.	Increased availability of fire protection given a seismic event.	Yes	A - Not Applicable	Seismic PRA and walkdowns did not identify this as a contributor.
160	Pressurizer PORV sticking open after loss of offsite power, Eliminate challenge by defeating the 100% load rejection capability.	Reduced frequency of pressurizer PORV sticking open	Yes	A - Not Applicable	Turbine trip above 49% power results in a direct reactor trip. BV does not have 100% load reject capability.
162	Provide a dedicated diesel driven fire water pump with supply tank to provide an additional source of water for SG tube coverage during SGTR events.	This would eliminate the LERF category and reduce all SGTR events to Small Early Releases.	Yes	A - Not Applicable	Not applicable. 2004 Strategic Action Plan identified this SAMA as only applicable to Unit 2.
185	Install Westinghouse RCP Shutdown seals to work with high temperature O-Rings.	Reduced seal LOCA probability	Yes	A - Not Applicable	Not applicable. This seal modification is not available.
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	Yes	B - Intent Met	Intent Met, Battery Chargers are dual charger units with only one side normally in operation.
7	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.	Yes	B - Intent Met	Intent met, part of the UPS design.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
8	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.	Yes	B - Intent Met	Loss of a single 120 VAC bus will induce transient. Procedures and training exist for operator response to loss of vital bus. If loss of two buses occurs, operators will implement both procedures.
10	Revise procedure to allow bypass of diesel generator trips.	Extended diesel generator operation.	Yes	B - Intent Met	Intent met. All non-essential EDG trips are bypassed upon emergency start.
11	Improve 4.16-kV bus cross-tie ability.	Increased availability of on-site AC power.	Yes	B - Intent Met	Intent met. Modifications installed.
12	Create AC power cross-tie capability with other unit (multi-unit site)	Increased availability of on-site AC power.	Yes	B - Intent Met	Intent met. Modifications installed.
16	Improve uninterruptible power supplies.	Increased availability of power supplies supporting front-line equipment.	Yes	B - Intent Met	Intent met. Inverters upgraded.
17	Create a cross-tie for diesel fuel oil (multi-unit site).	Increased diesel generator availability.	Yes	B - Intent Met	Intent Met. A fuel oil cross-tie does not exist between the units. Unit 1 does have redundant fuel oil transfer pumps in each train and a cross-tie between the Unit 1 trains. Unit 1 also has a fuel oil receiving tank capable of transferring fuel to either train.
18	Develop procedures for replenishing diesel fuel oil.	Increased diesel generator availability.	Yes	B - Intent Met	Intent met. Procedure exists.
19	Use fire water system as a backup source for diesel cooling.	Increased diesel generator availability.	Yes	B - Intent Met	Intent met. Procedure exists.
20	Add a new backup source of diesel cooling.	Increased diesel generator availability.	Yes	B - Intent Met	Intent met. Cross-connections and backups available.
21	Develop procedures to repair or replace failed 4 KV breakers.	Increased probability of recovery from failure of breakers that transfer 4.16 kV non-emergency buses from unit station service transformers.	Yes	B - Intent Met	Intent met - Existing procedures implement replacement. Spare breaker internals are available near the required locations.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
22	In training, emphasize steps in recovery of off-site power after an SBO.	Reduced human error probability during off-site power recovery.	Yes	B - Intent Met	Intent met. Included in training.
23	Develop a severe weather conditions procedure.	Improved off-site power recovery following external weather-related events.	Yes	B - Intent Met	Intent met. Procedure exists.
30	Improve ECCS suction strainers.	Enhanced reliability of ECCS suction.	Yes	B - Intent Met	Sump improvements being installed with a phased implementation process IAW GL 2004-02.
31	Add the ability to manually align emergency core cooling system recirculation.	Enhanced reliability of ECCS suction.	Yes	B - Intent Met	Intent met. Automatic with procedural manual backup,
32	Add the ability to automatically align emergency core cooling system to recirculation mode upon refueling water storage tank depletion.	Enhanced reliability of ECCS suction.	Yes	B - Intent Met	Intent met. Automatic with procedural manual backup,
33	Provide hardware and procedure to refill the reactor water storage tank once it reaches a specified low level.	Extended reactor water storage tank capacity in the event of a steam generator tube rupture (or other LOCAs challenging RWST capacity) .	Yes	B - Intent Met	Intent met. Procedure and connections exist.
36	Emphasize timely recirculation alignment in operator training.	Reduced human error probability associated with recirculation failure.	Yes	B - Intent Met	Intent met. Included in training.
40	Provide capability for remote, manual operation of secondary side pilot-operated relief valves in a station blackout.	Improved chance of successful operation during station blackout events in which high area temperatures may be encountered (no ventilation to main steam areas).	Yes	B - Intent Met	Intent met. Procedure exists and valves can be operated with hydraulic operator.
42	Make procedure changes for reactor coolant system depressurization.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	Yes	B - Intent Met	Intent met. Procedure exists.
43	Add redundant DC control power for SW pumps.	Increased availability of SW.	Yes	B - Intent Met	Swing Pump fulfills this function. Alternate river water pumps can be aligned to either header.
44	Replace ECCS pump motors with air-cooled motors.	Elimination of ECCS dependency on component cooling system.	Yes	B - Intent Met	Intent met. Per Expert Panel ECCS pump motors are air cooled.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
45	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.	Yes	B - Intent Met	Intent met. Procedures exist.
46	Add a service water pump.	Increased availability of cooling water.	Yes	B - Intent Met	Intent met. The alternate intake facility fulfills this function. An installed spare service water pump that can be aligned to either bus on either loop.
47	Enhance the screen wash system.	Reduced potential for loss of SW due to clogging of screens.	Yes	B - Intent Met	Intent met. Alternate Intake Facility. Alternate intake facility provides redundancy, there is a PM and monitoring program in place for the screens and screen wash system.
49	Enhance loss of component cooling water (or loss of service water) procedures to facilitate stopping the reactor coolant pumps.	Reduced potential for reactor coolant pump seal damage due to pump bearing failure.	Yes	B - Intent Met	Intent met. EOPs also direct operators to stop RCPs on loss of seal cooling.
50	Enhance loss of component cooling water procedure to underscore the desirability of cooling down the reactor coolant system prior to seal LOCA.	Reduced probability of reactor coolant pump seal failure.	Yes	B - Intent Met	Intent met. Procedures exist.
51	Additional training on loss of component cooling water.	Improved success of operator actions after a loss of component cooling water.	Yes	B - Intent Met	Intent met. Loss of component cooling water already included in the training program.
53	On loss of essential raw cooling water, proceduralize shedding component cooling water loads to extend the component cooling water heat-up time.	Increased time before loss of component cooling water (and reactor coolant pump seal failure) during loss of essential raw cooling water sequences.	Yes	B - Intent Met	Intent met. Procedure exists.
58	Install improved reactor coolant pump seals.	Reduced likelihood of reactor coolant pump seal LOCA.	Yes	B - Intent Met	Intent met. New design RCP seals installed. See also SAMAs 158 & 185.
59	Install an additional component cooling water pump.	Reduced likelihood of loss of component cooling water leading to a reactor coolant pump seal LOCA.	Yes	B - Intent Met	Installed spare CCR pump can be run off either bus.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
61	Change procedures to isolate reactor coolant pump seal return flow on loss of component cooling water, and provide (or enhance) guidance on loss of injection during seal LOCA.	Reduced frequency of core damage due to loss of seal cooling.	Yes	B - Intent Met	Intent met. Procedure exists.
66	Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	Increased availability of feedwater.	Yes	B - Intent Met	Intent met. Per Expert Panel - AFW has backup from river water, dedicated AFW pump has suction from two separate demin water tanks.
67	Install an independent diesel for the condensate storage tank makeup pumps.	Extended inventory in CST during an SBO.	Yes	B - Intent Met	Intent met. Per Expert Panel - Dedicated AFW pump is backed by ERF diesel generator and has suction from two separate demin water tanks.
68	Add a motor-driven feedwater pump.	Increased availability of feedwater.	Yes	B - Intent Met	Intent met. Per Expert Panel - Unit has dedicated motor driven AFW pump with power backup from ERF diesel generator. Feedwater pumps are motor driven.
70	Install accumulators for turbine-driven auxiliary feedwater pump flow control valves.	Eliminates the need for local manual action to align nitrogen bottles for control air following a loss of off-site power.	Yes	B - Intent Met	Implemented - TDAFW has no flow control valve. The min-flow valve is air-operated and the supply air is diesel backed. The motor driven trains have MOVs that can be manually manipulated.
71	Install a new condensate storage tank (auxiliary feedwater storage tank).	Increased availability of the auxiliary feedwater system.	Yes	B - Intent Met	Intent met. Per Expert Panel - Dedicated AFW pump is backed by ERF diesel generator and has suction from separate demin water tanks.
72	Modify the turbine-driven auxiliary feedwater pump to be self-cooled.	Improved success probability during a station blackout.	Yes	B - Intent Met	Intent met. Per Expert Panel - TDAFW is self cooled.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
73	Proceduralize local manual operation of auxiliary feedwater system when control power is lost.	Extended auxiliary feedwater availability during a station blackout. Also provides a success path should auxiliary feedwater control power be lost in non-station blackout sequences.	Yes	B - Intent Met	Intent met. During an SBO, no manual actions are needed for TDAFW operation.
74	Provide hookup for portable generators to power the turbine-driven auxiliary feedwater pump after station batteries are depleted.	Extended auxiliary feedwater availability.	Yes	B - Intent Met	ERF diesel generator can supply U1 dedicated AFW pump. TDAFW pump does not require DC power.
75	Use fire water system as a backup for steam generator inventory.	Increased availability of steam generator water supply.	Yes	B - Intent Met	Intent met. Service Water and River Water systems can be used as backup water source to AFW. Diesel fire water pump can be cross-tied to RW.
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	Yes	B - Intent Met	Intent met. The U1 dedicated AFW pump provides the same function; it is powered from the ERF diesel.
79	Replace existing pilot-operated relief valves with larger ones, such that only one is required for successful feed and bleed.	Increased probability of successful feed and bleed.	Yes	B - Intent Met	Beaver Valley has three pressurizer PORVs, only one is required for successful feed and bleed.
80	Provide a redundant train or means of ventilation.	Increased availability of components dependent on room cooling.	Yes	B - Intent Met	Switchgear room cooling system. Portable fans are available (not staged in switchgear room, but are nearby) as a backup and operators are trained on implementing the temporary ventilation system. Same for EDG Building HVAC.
81	Add a diesel building high temperature alarm or redundant louver and thermostat.	Improved diagnosis of a loss of diesel building HVAC.	Yes	B - Intent Met	No high temperature alarm, but alarm does exist for HVAC system trouble/trip. Portable fans are available for backup.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
82	Stage backup fans in switchgear rooms.	Increased availability of ventilation in the event of a loss of switchgear ventilation.	Yes	B - Intent Met	Intent met. Fans are not staged in switchgear room, but are nearby.
83	Add a switchgear room high temperature alarm.	Improved diagnosis of a loss of switchgear HVAC.	Yes	B - Intent Met	No high temperature alarm, but multiple alarms for fan trips. Backup fans are staged and a procedure exists for implementing temporary ventilation. Analysis shows long time available to implement temporary ventilation. Operators are trained on the procedure for temporary ventilation.
85	Provide cross-unit connection of uninterruptible compressed air supply.	Increased ability to vent containment using the hardened vent.	Yes	B - Intent Met	BV1 has a third train of station air supplied from diesel air compressor although the containment vent is not air operated.
86	Modify procedure to provide ability to align diesel power to more air compressors.	Increased availability of instrument air after a LOOP.	Yes	B - Intent Met	Intent met. Diesel powered air compressor installed.
87	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 service water cooling.	Yes	B - Intent Met	Third train of station air supplied from diesel air compressor; this compressor is self cooled.
88	Install nitrogen bottles as backup gas supply for safety relief valves.	Extended SRV operation time.	Yes	B - Intent Met	Implemented for the PORVs (accumulators), steam generators ADV's have manual operation capability; pressurizer and steam generator Safety Valves do not require air.
90	Create a reactor cavity flooding system.	Enhanced debris cool ability, reduced core concrete interaction, and increased fission product scrubbing.	Yes	B - Intent Met	This is being implemented at BV1 using existing systems as directed by SAMGs.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
92	Use the fire water system as a backup source for the containment spray system.	Improved containment spray capability.	Yes	B - Intent Met	Intent met. Procedures exist.
93	Install an unfiltered, hardened containment vent.	Increased decay heat removal capability for non-ATWS events, without scrubbing released fission products.	Yes	B - Intent Met	SAMG guidance contains guidance for a number of containment venting paths. Although not a dedicated hardened vent, redundant and separate venting paths exist.
95	Enhance fire protection system and standby gas treatment system hardware and procedures.	Improved fission product scrubbing in severe accidents.	Yes	B - Intent Met	Intent met. Included in SAMG.
103	Institute simulator training for severe accident scenarios.	Improved arrest of core melt progress and prevention of containment failure.	Yes	B - Intent Met	Intent met. Already included in the training program.
106	Install automatic containment spray pump header throttle valves.	Extended time over which water remains in the reactor water storage tank, when full containment spray flow is not needed.	Yes	B - Intent Met	Implemented IAW EOPs, not automatic, but manual as directed by procedures.
114	Install self-actuating containment isolation valves.	Reduced frequency of isolation failure.	Yes	B - Intent Met	Intent met. AOV, MOV and CV containment isolation valves; those that are required to close are AOVs and fail closed on loss-of-air, or are administratively controlled closed.
115	Locate residual heat removal (RHR) inside containment	Reduced frequency of ISLOCA outside containment.	Yes	B - Intent Met	Intent met. RHR pumps are located inside containment.
116	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.	Yes	B - Intent Met	Break flow is expected to submerge the break location; in addition, the fission product releases would pass through building ventilation which is filtered through the supplemental leak collection and release system.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
117	Revise EOPs to improve ISLOCA identification.	Increased likelihood that LOCAs outside containment are identified as such. A plant had a scenario in which an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment.	Yes	B - Intent Met	Intent met. EOPs provide guidance to eliminate other routes.
120	Replace steam generators with a new design.	Reduced frequency of steam generator tube ruptures.	Yes	B - Intent Met	Intent met. Steam Generators replaced with updated design with orifice on discharge to limit steam line rupture. Upgraded tube and tubesheet design.
123	Proceduralize use of pressurizer vent valves during steam generator tube rupture sequences.	Backup method to using pressurizer sprays to reduce primary system pressure following a steam generator tube rupture.	Yes	B - Intent Met	Intent met. Procedure exists.
124	Provide improved instrumentation to detect steam generator tube ruptures, such as Nitrogen-16 monitors).	Improved mitigation of steam generator tube ruptures.	Yes	B - Intent Met	Intent met. N-16 monitors installed.
127	Revise emergency operating procedures to direct isolation of a faulted steam generator.	Reduced consequences of a steam generator tube rupture.	Yes	B - Intent Met	Intent met by alternate means. Procedure EOP E-2 directs operators to isolate faulted SGs by closing all actuated or manual valves associated with the affected SG. SAMA 164 will enhance procedures to provide steps to isolate any stuck-open safety valves on a ruptured SG.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
128	Direct steam generator flooding after a steam generator tube rupture, prior to core damage.	Improved scrubbing of steam generator tube rupture releases.	Yes	B - Intent Met	Intent met by alternate means. Procedure EOP E-3 directs operators to feed ruptured SGs if the narrow range level is below 12%. SAMA 164, will enhance procedures to provide steps to; consider feeding a faulted-ruptured SG to provide continuous scrubbing (by maintaining ~12% to 50% narrow range SG level by throttling AFW flow to the ruptured SG), isolate any stuck-open safety valves on a ruptured SG, or close the RCS Loop Stop Valves on the ruptured SG to terminate or minimize the release.
132	Provide an additional control system for rod insertion (e.g., AMSAC).	Improved redundancy and reduced ATWS frequency.	Yes	B - Intent Met	Intent met. AMSAC installed.
138	Improve inspection of rubber expansion joints on main condenser.	Reduced frequency of internal flooding due to failure of circulating water system expansion joints.	Yes	B - Intent Met	Implemented - Program exists to inspect and replace expansion joints in the turbine building. No internal flooding sources of any risk significance identified.
142	Replace mercury switches in fire protection system.	Decreased probability of spurious fire suppression system actuation.	Yes	B - Intent Met	Intent met. Remaining mercury switches will not cause spurious suppression system actuations affecting plant equipment.
144	Install additional transfer and isolation switches.	Reduced number of spurious actuations during a fire.	Yes	B - Intent Met	Current fire protection safe shutdown procedures intentionally de-energize circuits to reduce the number of spurious actuations.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
145	Enhance fire brigade awareness.	Decreased consequences of a fire.	Yes	B - Intent Met	Fire brigade training and procedures meet current industry practices.
146	Enhance control of combustibles and ignition sources.	Decreased fire frequency and consequences.	Yes	B - Intent Met	Intent met. Procedure exists.
148	Enhance procedures to mitigate large break LOCA.	Reduced consequences of a large break LOCA.	Yes	B - Intent Met	Intent met. Owner's Group recommendations implemented.
149	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.	Yes	B - Intent Met	Safety Parameter Display System installed.
150	Improve maintenance procedures.	Improved prevention of core melt sequences by increasing reliability of important equipment.	Yes	B - Intent Met	Intent met. Maintenance procedures are written IAW current industry standards and guidance.
151	Increase training and operating experience feedback to improve operator response.	Improved likelihood of success of operator actions taken in response to abnormal conditions.	Yes	B - Intent Met	Training and operator experience feedback meets current industry standards and practices.
152	Develop procedures for transportation and nearby facility accidents.	Reduced consequences of transportation and nearby facility accidents.	Yes	B - Intent Met	Intent met but will be reevaluated (nearby industrial facilities) because the potential for impacts of the expanded propane storage facility being modified across the river from BV.
154	Provide Beaver Valley Units 1 and 2 with 4,160 V Bus Crosstie Capability	Adds a success path for blackout on Unit 2 when both Unit 1 diesel generators work, and vice versa	Yes	B - Intent Met	Cross-Tie installed
156	Operate plant with all PORV block valves open or provide procedures to open block valves when Main Feedwater is lost.	Increased pressure relief capacity to prevent reactor vessel rupture during ATWS.	Yes	B - Intent Met	Intent met. Normal operational alignment has all 3 block valves open. The configuration risk management program limits the amount of time the PORV block valves can remain closed..
157	Loss of Emergency Switchgear Room HVAC , Enhanced Loss of HVAC Procedures	Confidence that operators will prevent thermal damage to switchgear	Yes	B - Intent Met	Intent met. Procedure exists and equipment is staged.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
158	RCP Seal Cooling for Station Blackout, Potential modifications under review	Reduced frequency of RCP seal LOCA resulting from blackout	Yes	B - Intent Met	Intent met. High temperature seals installed.
159	Battery Capacity for steam generator level instruments for station blackout, Enhance procedures on shedding loads or using portable battery chargers. One train of the battery chargers will be powered from the site operable emergency diesel generator once the SBO unit cross-tie modification is complete.	Extended operating time for steam generator level instruments for less of all AC power scenarios	Yes	B - Intent Met	BVPS has committed to implement this SAMA using an alternate mitigation strategy using a portable generator to power the SG level instrumentation by the end of 2007.
161	Fast 4,160 V Bus Transfer Failure, Explicit Procedure and Training on breaker repair or change out	Reduced frequency that breaker failures will challenge diesel generators	Yes	B - Intent Met	Intent met - Existing procedures implement replacement. Spare breaker internals are available near the required locations.
163	Modify Loss of DC AOP to proceduralize the use of backup battery chargers.	Provide better reliability of the DC busses.	Yes	B - Intent Met	Intent met. Procedure exists.
181	Refine Emergency Switchgear room heatup analysis to provide additional time margin.	IPEEE fire issue for CS-1 fire, SW corner.	Yes	B - Intent Met	This fire impacts the switchgear ventilation fans and is already identified in SAMAs Per Expert Panel -the switchgear room heatup analysis has been performed and shows five hours available to install backup ventilation.
9	Provide an additional diesel generator.	Increased availability of on-site emergency AC power.	Yes	C - Combined	Intent met. Reference SAMA 154.
143	Upgrade fire compartment barriers.	Decreased consequences of a fire.	Yes	C - Combined	Retain for Phase II analysis. See also SAMA 168 for same item.
179	Emergency 125V DC battery room block walls Seismic concern from IPEEE.	Reevaluate block wall fragility, reinforce block walls, or shield batteries.	Yes	C - Combined	Retain for Phase II analysis. See also SAMA 167.
24	Bury off-site power lines.	Improved off-site power reliability during severe weather.	Yes	D - Excess Cost	Excessive Implementation Cost

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
34	Provide an in-containment reactor water storage tank.	Continuous source of water to the safety injection pumps during a LOCA event, since water released from a breach of the primary system collects in the in-containment reactor water storage tank, and thereby eliminates the need to realign the safety injection pumps for long-term post-LOCA recirculation.	Yes	D - Excess Cost	Excessive Implementation Cost
77	Provide a passive, secondary-side heat-rejection loop consisting of a condenser and heat sink.	Reduced potential for core damage due to loss-of-feedwater events.	Yes	D - Excess Cost	Excessive Implementation Cost
91	Install a passive containment spray system.	Improved containment spray capability.	Yes	D - Excess Cost	Excessive Implementation Cost
97	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.	Yes	D - Excess Cost	Excessive Implementation Cost
99	Strengthen primary/secondary containment (e.g., add ribbing to containment shell).	Reduced probability of containment over-pressurization.	Yes	D - Excess Cost	Expert Panel >MAB
100	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.	Yes	D - Excess Cost	Excessive Implementation Cost
101	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.	Yes	D - Excess Cost	Excessive Implementation Cost
102	Construct a building to be connected to primary/secondary containment and maintained at a vacuum.	Reduced probability of containment over-pressurization.	Yes	D - Excess Cost	Excessive Implementation Cost
110	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.	Yes	D - Excess Cost	Excessive Implementation Cost

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
121	Increase the pressure capacity of the secondary side so that a steam generator tube rupture would not cause the relief valves to lift.	Eliminates release pathway to the environment following a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
125	Route the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove most of the fission products.	Reduced consequences of a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
126	Install a highly reliable (closed loop) steam generator shell-side heat removal system that relies on natural circulation and stored water sources	Reduced consequences of a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
129	Vent main steam safety valves in containment.	Reduced consequences of a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
1	Provide additional DC battery capacity.	Extended DC power availability during an SBO.	No		Retain for Phase II analysis.
2	Replace lead-acid batteries with fuel cells.	Extended DC power availability during an SBO.	No		Retain for Phase II analysis.
4	Improve DC bus load shedding.	Extended DC power availability during an SBO.	No		Retain for Phase II analysis.
5	Provide DC bus cross-ties.	Improved availability of DC power system.	No		Retain for Phase II analysis. Limited cross-tie capability exists.
6	Provide additional DC power to the 120/240V vital AC system.	Increased availability of the 120 V vital AC bus.	No		Retain for Phase II analysis.
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	No		Retain for Phase II analysis.
14	Install a gas turbine generator.	Increased availability of on-site AC power.	No		ERF diesel generator has limited ability to power plant loads. Retain for Phase II analysis.
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	No		Retain for Phase II analysis.
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
28	Add a diverse low pressure injection system.	Improved injection capability.	No		Retain for Phase II analysis.
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	No		Retain for Phase II analysis.
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	No		Retain for Phase II analysis.
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injections systems.	No		Retain for Phase II analysis.
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	No		Retain for Phase II analysis.
48	Cap downstream piping of normally closed component cooling water drain and vent valves.	Reduced frequency of loss of component cooling water initiating events, some of which can be attributed to catastrophic failure of one of the many single isolation valves.	No		Vents and drains are capped with exceptions.
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	No		Retain for Phase II analysis.
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	No		Retain for Phase II analysis.
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	No		Retain for Phase II analysis.
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	No		Retain for Phase II analysis. Digital feedwater not installed and not planned.
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	No		Retain for Phase II analysis.
94	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.	No		SAMG guidance contains guidance for a number of containment venting paths. Some of these vent paths are filtered. Retain for Phase II analysis.
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	No		Retain for Phase II analysis.
98	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.	No		Retain for Phase II analysis.
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	No		Retain for Phase II analysis.
107	Install a redundant containment spray system.	Increased containment heat removal ability.	No		Retain for Phase II analysis.
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	No		Retain for Phase II analysis.
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	No		Retain for Phase II analysis.
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	No		Retain for Phase II analysis.
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	No		Retain for Phase II analysis.
122	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture	Enhanced depressurization capabilities during steam generator tube rupture.	No		Retain for Phase II analysis.
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	No		Retain for Phase II analysis.
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	No		Retain for Phase II analysis.
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	No		Retain for Phase II analysis.
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	No		Retain for Phase II analysis.
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	No		Retain for Phase II analysis. Capability exists outside the control room, but action takes too long to perform.
147	Install digital large break LOCA protection system.	Reduced probability of a large break LOCA (a leak before break).	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	No		Retain for Phase II analysis.
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	No		Retain for Phase II analysis. Capability exists outside the control room, but action takes too long to perform.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	No		Retain for Phase II analysis.
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	No		Retain for Phase II analysis.
166	Provide additional emergency 125V DC battery capability.	Better coping for long term station blackouts	No		Retain for Phase II analysis.
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	No		Retain for Phase II analysis. The block walls have been evaluated and found satisfactory. See also SAMA 179.
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	No		Retain for Phase II analysis. See also SAMA 143 for same item.
169	Improve operator performance. Operator starts Aux RW pump given offsite power is available.	One of top 10 operator actions, OPRWA1	No		Retain for Phase II analysis.
170	Improve operator performance. Operator starts portable fans & open doors in emergency switchgear room	One of top 10 operator actions, OPRWBV3	No		Retain for Phase II analysis.
171	Improve operator performance. Operator initiates Safety Injection	One of top 10 operator actions, OPROS6	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
172	Improve operator performance. Operator initiates bleed and feed cooling given failure of prior actions to restore feedwater systems.	One of top 10 operator actions, OPROB2	No		Retain for Phase II analysis.
173	Improve operator performance. Operator initiates makeup of RWST	One of top 10 operator actions, OPRWM1	No		Retain for Phase II analysis.
174	Improve operator performance. Operator trips RCPs during loss of CCR.	One of top 10 operator actions, OPROC1	No		Retain for Phase II analysis.
175	Improve operator performance. Operator initiates depressurization of RCS given a general transient initiating event.	One of top 10 operator actions, OPROD2	No		Retain for Phase II analysis.
176	Improve operator performance. Operator initiates depressurization of RCS given a SGTR event.	One of top 10 operator actions, OPROD1	No		Retain for Phase II analysis.
177	Improve operator performance. Operator initiates cooldown and depressurization of RCS given a Small LOCA and failure of HHSI.	One of top 10 operator actions, OPRCD6	No		Retain for Phase II analysis.
178	Improve operator performance. Operator aligns hot leg recirculation.	One of top 10 operator actions, OPRLR1	No		Retain for Phase II analysis.
180	Reroute River Water pump power cable	IPEEE issue with CV-3 fire.	No		Retain for Phase II analysis.
182	Reroute CCR pump or HHSI suction MOV cables.	IPEEE fire issue for PA-1 fire.	No		Retain for Phase II analysis.
183	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for CS-1 fire, NE corner.	No		Retain for Phase II analysis.
184	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for NS-1 fire, south wall.	No		Retain for Phase II analysis.
186	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
187	Increase seismic ruggedness of the ERF Substation batteries. This applies to the battery rack only and not the entire structure.	Increased reliability of the ERF diesel following seismic events	No		Retain for Phase II analysis.
188	Install a cross-tie between the Unit 1 and Unit 2 RWST.	Increased availability of the RWST for injection.	No		Retain for Phase II analysis.
189	Provide Diesel backed power for the fuel pool purification pumps and valves used for makeup to the RWST.	Increased availability of the RWST during loss of offsite power and station blackout events.	No		Retain for Phase II analysis. This SAMA to provide procedure changes and temporary power jumpers.

7 PHASE II SAMA ANALYSIS

A cost-benefit analysis was performed on each of the SAMA candidates remaining after the Phase I screening. The benefit of a SAMA candidate is the difference between the baseline cost of severe accident risk (maximum benefit from Section 4.5) and the cost of severe accident risk with the SAMA implemented (Section 7.1). The cost figure used is the estimated cost to implement the specific SAMA. If the estimated cost of implementation exceeds the benefit of implementation, the SAMA is not cost-beneficial.

Since the SAMA analysis is being performed separately for each Beaver Valley unit, the costs and the benefits are provided on a per-unit basis. If a SAMA candidate is shared by the units, that information is noted in the Phase II SAMA candidate list and it is analyzed in a manner consistent with its applicability to both units.

7.1 SAMA BENEFIT

7.1.1 Severe Accident Risk with SAMA Implemented

Bounding analyses were used to determine the change in risk following implementation of SAMA candidates or groups of similar SAMA candidates. For each analysis case, the Level 1 internal events or Level 2 PRA models were altered to conservatively consider implementation of the SAMA candidate(s). Then, severe accident risk measures were calculated using the same procedure used for the baseline case described in Section 3. The changes made to the PRA models for each analysis case are described in Appendix A.

A "bounding analyses" are exemplified by the following:

LBLOCA

This analysis case was used to evaluate the change in plant risk profile that would be achieved if a digital large break LOCA protection system was installed. Although the proposed change would not completely eliminate the potential for a large break LOCA, a bounding benefit was estimated by removing the large break LOCA initiating event. This analysis case was used to model the benefit of SAMA xx.

DCPWR

This analysis case was used to evaluate plant modifications that would increase the availability of Class 1E DC power (e.g., increased battery capacity or the installation of a diesel-powered generator that would effectively increase battery capacity). Although the proposed SAMAs would not completely eliminate the potential failure, a bounding benefit was estimated by removing the *battery discharge events and battery failure events. This analysis case was used to model the benefit of SAMAs a, b, etc.*

The severe accident risk measures were obtained for each analysis case by modifying the baseline model in a simple manner to capture the effect of implementation of the SAMA in a bounding manner. Bounding analyses are very conservative and result in overestimation of the benefit of the candidate analyzed. However, if this bounding assessment yields a benefit that is smaller than the cost of implementation, then the effort involved in refining the PRA modeling approach for the SAMA would be unnecessary because it would only yield a lower benefit result. If the benefit is greater than the cost when modeled in this bounding approach, it is necessary to refine the PRA model of the SAMA to remove conservatism. As a result of this modeling approach, models representing the Phase II SAMAs will not all be at the same level of detail and if any are implemented, the PRA result after implementation of the final installed design will differ from the screening-type analyses done during this evaluation.

7.1.2 Cost of Severe Accident Risk with SAMA Implemented

Using the risk measures determined as described in Section 7.1.1, severe accident impacts in four areas (offsite exposure cost, off-site economic cost, on-site exposure cost, and on-site economic cost) were calculated using the same procedure used for the baseline case described in Section 4. As in Section 4.5, the severe accident impacts were summed to estimate the total cost of severe accident risk with the SAMA implemented.

7.1.3 SAMA Benefit Calculation

The respective SAMA benefit was calculated by subtracting the total cost of severe accident risk with the SAMA implemented from the baseline cost of severe accident risk (maximum benefit from Section 4.5). The estimated benefit for each SAMA candidate is listed in Table 7-1. The calculation of the benefit is performed using an Excel spreadsheet.

7.2 COST OF SAMA IMPLEMENTATION

The final step in the evaluation of the SAMAs is estimating the cost of implementation for comparison with the benefit. For the purpose of this analysis the BVPS staff has estimated that the cost of making a change to a procedure and for conducting the necessary training on a procedure change is expected to exceed **$15,000**. Similarly, the minimum cost associated with development and implementation of an integrated hardware modification package (including post-implementation costs, e.g. training) was assumed to be **$100,000**. These values were used for comparison with the benefit of SAMAs.

The benefits resulting from the bounding estimates presented in the benefit analysis are in some cases rather low. In those cases for which the benefits are so low that it is obvious that the implementation costs would exceed the benefit, a detailed cost estimate was not warranted. Plant staff judgment is applied in assessing whether the benefit approaches the expected implementation costs in many cases.

Plant staff judgment was obtained from an independent, expert panel consisting of senior staff members from the PRA group, the design group, operations and license renewal. This panel reviewed the benefit calculation results and, based upon their experience with developing and implementing modifications at the plant, judged whether a modification could be made to the plant that would be cost beneficial in comparison with the calculated benefit. The purpose of this approach was to minimize the effort expended on detailed cost estimation. The cost estimations provided by the expert panel are included in Table 7-1 along with the conclusions reached for each SAMA evaluated for cost/benefit.

It should be noted that the results of the sensitivities of Section 8 influenced the decisions of whether a SAMA was considered to be potentially cost beneficial. If the benefits calculated in the sensitivity analyses exceeded the estimated cost of the SAMA, it was considered potentially cost beneficial.

7.3 SAMAs WITH SHARED BENEFIT OR COSTS

A number of SAMAs either benefit both BVPS-1 and BVPS-2 or the cost of implementation would be shared by both units. In this case, consideration of the costs and benefits at only one unit is not appropriate.

SAMA 14, installation of a gas turbine generator, would provide benefit for both units. The maximum combined benefit for this SAMA is $ 1.9 million ($400K in Unit 1 and $1,495K in Unit 2). The cost to implement this SAMA is greater than $7 million. Even with the combined benefit, this SAMA is not cost beneficial.

SAMA 187 (Unit 1) and 186 (Unit 2), increase the seismic ruggedness of the ERF Substation batteries, would provide benefit for both units. Currently the ERF diesel generator can provide power to the Unit 1 Dedicated AFW system, but very little equipment on Unit 2. The benefit of this SAMA to Unit 2 is $3.8K compared to the Unit 1 benefit of $525K. The estimated cost for implementing this SAMA is $300K. This SAMA is considered potentially cost beneficial for BVPS-1, but not for BVPS-2.

SAMA 186 (Unit 1) and 190 (Unit 2), provide a containment cross-tie between the units, would provide benefit to both units. However, the result of using this cross-tie to mitigate an event would result in contamination of both units. The cost of cleanup of the opposite unit is not included in the benefit calculation. Due to the high cost of implementation and the impact on the opposite unit, this SAMA is not considered cost beneficial for either unit.

Unit 1 SAMA 188 (RWST cross-tie) would provide a benefit for both units. However, since the Unit 2 RWST is significantly larger than the Unit 1 RWST, the benefit to Unit 2 would be small and was therefore not considered as a SAMA. The high cost of implementation (>$4,000K), therefore, makes this SAMA not cost beneficial (at either unit).

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
1	Provide additional DC battery capacity.	Extended DC power availability during an SBO.	0.00%	0.26%	DC01	Assumed no failure or depletion of DC power system.	$13.9K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
2	Replace lead-acid batteries with fuel cells.	Extended DC power availability during an SBO.	0.00%	0.26%	DC01	Assumed no failure or depletion of DC power system.	$13.9K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
4	Improve DC bus load shedding.	Extended DC power availability during an SBO.	0.00%	0.26%	DC01	Assumed no failure or depletion of DC power system.	$13.9K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
5	Provide DC bus cross-ties.	Improved availability of DC power system.	0.00%	0.26%	DC01	Assumed no failure or depletion of DC power system.	$13.9K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
6	Provide additional DC power to the 120/240V vital AC system.	Increased availability of the 120 V vital AC bus.	0.00%	0.26%	DC01	Assumed no failure or depletion of DC power system.	$13.9K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	1.27%	1.27%	NOLOSP	This case was used to determine the benefit of eliminating all loss of offsite power events, both as the initiating event and subsequent to a different initiating event. This allows evaluation of various possible improvements that could reduce the risk associated with loss of offsite power events. For the purposes of the analysis, a single bounding analysis was performed which assumed that loss of offsite power events do not occur, both as an initiating event and subsequent to a different initiating event.	$73.7K	>$2,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
14	Install a gas turbine generator.	Increased availability of on-site AC power.	11.21%	7.46%	NOSBO	This case is used to determine the benefit of eliminating all Station Blackout events. This allows evaluation of possible improvements related to SBO sequences. For the purpose of the analysis, a single bounding analysis is performed that assumes the Diesel Generators do not fail.	$400K	>$7,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 14 in Unit 2. See report section 7.3.	Cost exceeds benefit.
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	0.52%	0.42%	LOCA02	Assumed high pressure injection does not fail; works perfectly.	$23.7K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	0.52%	0.42%	LOCA02	Assumed high pressure injection does not fail; works perfectly.	$23.7K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
28	Add a diverse low pressure injection system.	Improved injection capability.	0.00%	0.02%	LOCA03	Assumed low pressure injection system does not fail.	$2.1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	0.00%	0.02%	LOCA03	Assumed low pressure injection system does not fail.	$2.1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	1.03%	0.89%	LOCA01	Eliminated all small LOCA events.	$48.0K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injections systems.	0.52%	0.42%	LOCA02	Assumed high pressure injection does not fail; works perfectly.	$23.7K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	1.03%	0.89%	LOCA01	Eliminated all small LOCA events.	$48.0K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
48	Cap downstream piping of normally closed component cooling water drain and vent valves.	Reduced frequency of loss of component cooling water initiating events, some of which can be attributed to catastrophic failure of one of the many single isolation valves.	0.00%	0.01%	CCW01	Assumed CCW pumps do not fail.	<$1K	>$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	0.00%	0.00%	CHG01	Remove the dependency of the charging pumps on cooling water.	<$1K	>$300K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	28.87%	24.74%	RCPLOCA2	This case is used to determine the benefit of eliminating all RCP seal LOCA events. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.	$1,303K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	28.87%	24.74%	RCPLOCA2	This case is used to determine the benefit of eliminating all RCP seal LOCA events. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.	$1,303K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	0.00%	0.01%	CCW01	Assumed CCW pumps do not fail.	<$1K	>$15K	Screening Procedure Change Value	Not Cost-Beneficial	Cost exceeds benefit.
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	1.55%	0.61%	FW01	Eliminated all loss of feedwater initiators.	$37.2K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	0.00%	0.00%	INSTAIR1	This case was used to determine the benefit of replacing the air compressors. For the purposes of the analysis, a single bounding analysis was performed which assumed the service and instrument air compressors do not fail.	<$1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
94	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.	0.00%	26.57%	CONT01	Eliminated all failures of containment due to overpressure.	$1,239K	$9,000K	Industry studies (NUREG 1437 supplements), with inflation	Not Cost-Beneficial	Some venting capability currently exists but the post-accident environment could preclude venting. A different vent was considered necessary to assure continued filtering.
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	0.00%	0.49%	H2BURN	Eliminated all Hydrogen detonation.	$30.4K	>$500K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Hydrogen recombiners previously abandoned in place.
98	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.	0.00%	0.49%	H2BURN	Eliminated all Hydrogen detonation.	$30.4K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Hydrogen recombiners previously abandoned in place.
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	0.52%	0.16%	LOCA05	Eliminated all piping failure LOCAs.	$10.7K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Have implemented RI-ISI.
107	Install a redundant containment spray system.	Increased containment heat removal ability.	0.00%	26.57%	CONT01	Eliminated all failures of containment due to overpressure.	$1,239K	$10,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	0.00%	0.17%	LOCA06	Eliminated all ISLOCA events.	$9.9K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	0.00%	0.11%	CONT02	Eliminated all containment isolation failures.	$5.8K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	0.00%	0.17%	LOCA06	Eliminated all ISLOCA events.	$9.9K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Increased outage frequency/duration.
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	0.00%	0.17%	LOCA06	Eliminated all ISLOCA events.	$9.9K	See Note 1.	See Note 1.	Not Cost-Beneficial	The current operating procedures and training meet industry standards and include place-keeping and check-off. No cost beneficial improvements could be identified to either training or procedures that would result in a significant change the HEP. Not cost beneficial.
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	0.00%	0.46%	NOSGTR	This case was used to determine the benefit of eliminating all SGTR events. This allows evaluation of various possible improvements that could reduce the risk associated with SGTR events. For the purposes of the analysis, a single bounding analysis was performed which assumed that SGTR events do not occur.	$31.5K	>$3,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
122	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture	Enhanced depressurization capabilities during steam generator tube rupture.	0.00%	0.46%	NOSGTR	This case was used to determine the benefit of eliminating all SGTR events. This allows evaluation of various possible improvements that could reduce the risk associated with SGTR events. For the purposes of the analysis, a single bounding analysis was performed which assumed that SGTR events do not occur.	$31.5K	>$100K	Expert Panel -Screening hardware change value.	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	1.74%	0.09%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$13.3K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	1.74%	0.09%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$13.3K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	1.74%	0.09%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$13.3K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	1.74%	0.09%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$13.3K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	1.74%	0.09%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$13.3K	>$100K	Expert Panel - 2004 Strategic Action Plan	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
147	Install digital large break LOCA protection system.	Reduced probability of a large break LOCA (a leak before break).	0.52%	0.16%	LOCA05	Eliminated all piping failure LOCAs.	$10.7K	>$100K	Expert Panel - Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	0.00%	0.01%	NOSLB	This case was used to determine the benefit of installing secondary side guard pipes up to the MSIVs. This would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. For the purposes of the analysis, a single bounding analysis was performed which assumed that no steam line break events occur.	<$1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
155	Reactor Trip breaker failure, Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	1.74%	0.09%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$13.3K	>$100K	Expert Panel - Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	0.00%	0.46%	NOSGTR	This case was used to determine the benefit of eliminating all SGTR events. This allows evaluation of various possible improvements that could reduce the risk associated with SGTR events. For the purposes of the analysis, a single bounding analysis was performed which assumed that SGTR events do not occur.	$31.5K	$50K	Expert Panel	Potentially Cost-Beneficial (because the upper bound sensitivity benefit exceeds the cost)	SAMA is potentially cost beneficial. Loop stop valves are also not designed to close against differential pressure and under accident conditions will not fully seat since hoses must be installed to provide pressure between the seats to fully seat the valve.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	28.87%	24.74%	RCPLOCA2	This case is used to determine the benefit of eliminating all RCP seal LOCA events. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.	$1,303K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
166	Provide additional emergency 125V DC battery capability.	Better coping for long term station blackouts	0.00%	0.26%	DC01	Assumed no failure or depletion of DC power system.	$13.9K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	15.46%	26.43%	DC02	Evaluated the impact of increasing the seismic ruggedness of the 125VDC battery room block walls.	$1,302K	$300K	Expert Panel	Potentially Cost-Beneficial	Potentially cost beneficial
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	1.55%	2.69%	FIRE01	Eliminated all fires impacting the switchgear HVAC fans.	$133K	$80K	Expert Panel	Potentially Cost-Beneficial	Potentially cost beneficial, reference SAMA 143
169	Improve operator performance. Operator starts Aux RW pump given offsite power is available.	One of top 10 operator actions, OPRWA1	0.00%	0.06%	HEP1	Reduced the probability of basic event OPRWA1 by a factor of 3.	$3.2K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
170	Improve operator performance. Operator starts portable fans & open doors in emergency switchgear room	One of top 10 operator actions, OPRWBV3	1.04%	1.89%	HEP2	Reduced the probability of basic event OPRWBV3 by a factor of 3.	$93.4K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
171	Improve operator performance. Operator initiates Safety Injection	One of top 10 operator actions, OPROS6	0.00%	0.06%	HEP3	Reduced the probability of basic event OPROS6 by a factor of 3.	$3.0K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
172	Improve operator performance. Operator initiates bleed and feed cooling given failure of prior actions to restore feedwater systems.	One of top 10 operator actions, OPROB2	2.66%	0.82%	HEP4	Reduced the probability of basic event OPROB2 by a factor of 3.	$56.7K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
173	Improve operator performance. Operator initiates makeup of RWST	One of top 10 operator actions, OPRWM1	0.00%	0.01%	HEP5	Reduced the probability of basic event OPRWM1 by a factor of 3.	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
174	Improve operator performance. Operator trips RCPs during loss of CCR.	One of top 10 operator actions, OPROC1	0.00%	0.19%	HEP6	Reduced the probability of basic event OPROC1 by a factor of 3.	$9.8K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
175	Improve operator performance. Operator initiates depressurization of RCS given a general transient initiating event.	One of top 10 operator actions, OPROD2	0.00%	0.01%	HEP7	Reduced the probability of basic event OPROD2 by a factor of 3.	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
176	Improve operator performance. Operator initiates depressurization of RCS given a SGTR event.	One of top 10 operator actions, OPROD1	0.00%	0.00%	HEP8	Reduced the probability of basic event OPROD1 by a factor of 3.	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
177	Improve operator performance. Operator initiates cooldown and depressurization of RCS given a Small LOCA and failure of HHSI.	One of top 10 operator actions, OPRCD6	0.00%	0.01%	HEP9	Reduced the probability of basic event OPRCD6 by a factor of 3.	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
178	Improve operator performance. Operator aligns hot leg recirculation.	One of top 10 operator actions, OPRLR1	0.00%	0.00%	HEP10	Reduced the probability of basic event OPRLR1 by a factor of 3.	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
180	Reroute River Water pump power cable	IPEEE issue with CV-3 fire.	0.52%	0.56%	SW01	Removed the DC power dependency for the service water/river water pumps.	$30.2K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
182	Reroute CCR pump or HHSI suction MOV cables.	IPEEE fire issue for PA-1 fire.	0.00%	0.00%	FIRE02	This case eliminates the fires in zone PA-1E causing failure of component cooling water and of seal injection.	<$1K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
183	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for CS-1 fire, NE corner.	2.06%	3.31%	FIRE03	This case eliminates the fires in zone CS-1, northeast corner, that cause failure of both river water pumps and both auxiliary river water pumps.	$163K	>$2,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
184	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for NS-1 fire, south wall.	1.03%	0.93%	FIRE04	This case eliminates the fires in zone NS-1 that cause total loss of river water.	$50.0K	>$2,000	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
186	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	0.00%	26.57%	CONT01	Eliminated all failures of containment due to overpressure.	$1,239K	>$10,000 K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 190 in Unit 2. See report section 7.3.	Cost exceeds benefit.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
187	Increase seismic ruggedness of the ERF Substation batteries. This applies to the battery rack only and not the entire structure.	Increased reliability of the ERF diesel following seismic events	14.95%	9.82%	SEISMIC1	This case assumes a seismic ruggedness for the ERF Substation battery that is the same as that for the station batteries.	$525K	$300K	Expert Panel	Potentially Cost-Beneficial. This SAMA affects both units; see SAMA 186 in Unit 2. See report section 7.3.	Potentially Cost-Beneficial
188	Install a cross-tie between the Unit 1 and Unit 2 RWST.	Increased availability of the RWST for injection.	17.01%	13.77%	LOCA04	Assumed RWST does not run out of water.	$729K	>$4,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; the Unit 2 affect is too small to be identified as a SAMA. See report section 7.3.	Cost will exceed benefit. BVPS plans to implement this SAMA by using an alternate mitigation strategy that will provide portable pumps that can be used for RWST makeup by the end of 2007.
189	Provide Diesel backed power for the fuel pool purification pumps and valves used for makeup to the RWST.	Increased availability of the RWST during loss of offsite power and station blackout events.	17.01%	13.77%	LOCA04	Assumed RWST does not run out of water.	$729K	$200K	Expert panel	Potentially Cost-Beneficial	Potentially cost beneficial. BVPS plans to implement this SAMA by using an alternate mitigation strategy that will provide portable pumps that can be used for RWST makeup by the end of 2007.

Note 1 – The current plant procedures and training meet current industry standards. The benefit calculation results provided in this table are based upon an arbitrary reduction in HEP of a factor of 3 and are provided solely to demonstrate the sensitivity of the model to change in the HEP. There are no additional specific procedure improvements that could be identified that would affect the result of the HEP calculations to this level of reduction. Therefore, it is expected that the idealistic benefits presented in the table are not achievable with procedure improvements only and would require additional hardware modifications. In all cases the costs of hardware and procedure changes would exceed the idealistic benefits presented in the table. These SAMAs are, therefore, screened as Not Cost Beneficial.

8 SENSITIVITY ANALYSES

The purpose of performing sensitivity analyses is to examine the impact of analysis assumptions on the results of the SAMA evaluation. This section identifies several sensitivities that can be performed during SAMA (Reference 24, NEI 05-01) and discusses the sensitivity as is applies to Beaver Valley Unit 1 and the impact of the sensitivity on the results of the Phase II SAMA analysis at BVPS-1.

Unless it was otherwise noted, it is assumed in these sensitivity analyses that sufficient margin existed in the maximum benefit estimation that the Phase I screening would not have to be repeated in the sensitivity analyses.

8.1 PLANT MODIFICATIONS

There are no plant modifications that are currently pending that would be expected to impact the results of this SAMA evaluation.

8.2 UNCERTAINTY

Since the inputs to PRA cannot be known with complete certainty, there is possibility that the actual plant risk is greater than the mean values used in the evaluation of the SAMA described in the previous sections. To consider this uncertainty, a sensitivity analysis was performed in which an uncertainty factor was applied to the frequencies calculated by the PRA and the subsequent benefits were calculated based upon the mean risk values multiplied by this uncertainty factor. The uncertainty factor applied is the ratio of the 95th percentile value of the CDF from the PRA uncertainty analysis to the mean value of the CDF. For Unit 1 the 95th percentile value of the CDF is 3.96E-5/yr; therefore, uncertainty factor is 2.04. Table 8-1 provides the benefit results from each of the sensitivities for each of the SAMA cases evaluated.

8.3 PEER REVIEW FACTS/OBSERVATIONS

The model used in this SAMA analysis includes the resolution of the Facts-and-Observations (F&Os) identified during the PRA Peer Review. Therefore, no specific sensitivities were performed related to this issue.

8.4 EVACUATION SPEED

Three evacuation sensitivity cases were performed to determine the impact of evacuation assumptions. One sensitivity case reduced the evacuation speed by a factor of four (0.05 m/sec) and the second increased the speed to 2.24 m/s. The third sensitivity case assumed a factor of 1.5 increase in the alarm time, thus delaying the commencement of physical evacuation.

The base evacuation speed was derived in a conservative manner assuming inclement weather and persons without transportation an average evacuation speed of 0.2 m/s was determined. A decrease in the evacuation speed by a factor of four to 0.05 m/s would have the impact of taking over 2 days to evacuate. Runs with an increase to 2.24 m/s (approximately 5 mph) were also performed to assess the slope and relative sensitivity of the dose to evacuation speed.

The third sensitivity case performed was a delay in the alarm time to simulate problems in communication that might be experienced during the night or severe weather. The alarm delay was multiplied by a factor of 1.5 for this case.

The results of the evacuation sensitivity runs indicated that Mean Total Economic Costs are very insensitive to evacuations speeds. Decreasing the evacuation speed had a maximum impact of 10 percent on total dose. Total dose was not sensitive to a delay on the alarm time. The Mean Population Exceeding 0.05 Sv showed some sensitivity to evacuation speed for the late containment failures. The tables below provide a summary of the evacuation sensitivity results.

Table 8.4-1 Evacuation Speed Sensitivity Results

Release Category	Base Note 1	Evacuation Speed				Alarm Delay	
		Slower (0.11 mph	Percent Change	Faster (5 mph)	Percent Change	1.5 x OALARM	Percent Change
Mean L-EFFECTIVE TOT LIF Dose (Sv)							
INTACT	8	8	1	8	-3	8	0
ECF							
VSEQ	50,400	53,700	7	42,700	-15	50,100	-1
SGTR	44,500	47,400	7	40,500	-9	44,700	0
DCH	86,800	88,900	2	81,500	-6	86,800	0
SECF							
SGTR	50,500	55,500	10	29,000	-43	50,500	0
LOCI	35,200	37,200	6	31,700	-10	35,300	0
BV5	43,800	46,400	6	34,600	-21	44,200	1
LATE							
Large	1,530	1,540	1	1,470	-4	1,540	1
Small	20,200	21,400	6	20,200	0	20,300	0
H2 Burn	19,300	19,900	3	18,700	-3	19,400	1
BMMT	7,680	7,850	2	7,670	0	7,680	0
Mean Population Exceeding 0.05 Sv							
INTACT	0	0	0	0	0	0	0
ECF							
VSEQ	143,000	143,000	0	138,000	-3	143,000	0
SGTR	154,000	154,000	0	147,000	-5	154,000	0
DCH	274,000	275,000	0	266,000	-3	274,000	0
SECF							
SGTR	80,200	80,700	1	72,400	-10	80,200	0
LOCI	37,600	38,400	2	28,300	-25	37,400	-1
BV5	86,700	87,200	1	80,100	-8	86,900	0
LATE							
Large	2	27	1,499	2	-8	3	62
Small	7,170	12,900	80	7,150	0	7,240	1
H2 Burn	21,700	24,700	14	18,500	-15	23,000	6
BMMT	2,210	2,730	24	2,200	0	2,240	1
Mean Total Economic Costs ($)							
INTACT	6.400E+03	6.400E+03	0	6.400E+03	0	6.400E+03	0
ECF							
VSEQ	3.530E+10	3.530E+10	0	3.530E+10	0	3.530E+10	0
SGTR	4.280E+10	4.280E+10	0	4.280E+10	0	4.280E+10	0
DCH	4.800E+10	4.800E+10	0	4.800E+10	0	4.800E+10	0
SECF							
SGTR	2.540E+10	2.540E+10	0	2.540E+10	0	2.540E+10	0
LOCI	2.650E+10	2.650E+10	0	2.650E+10	0	2.650E+10	0
BV5	1.130E+10	1.130E+10	0	1.130E+10	0	1.130E+10	0
LATE							
Large	1.180E+08	1.180E+08	0	1.180E+08	0	1.180E+08	0
Small	1.090E+10	1.090E+10	0	1.090E+10	0	1.090E+10	0
H2 Burn	6.670E+09	6.670E+09	0	6.670E+09	0	6.670E+09	0
BMMT	4.380E+09	4.380E+09	0	4.380E+09	0	4.380E+09	0

Note 1 Current Economic data, 2047 population data, and 2001 met data

8.5 REAL DISCOUNT RATE

Calculation of severe accident impacts in the BVPS-1 SAMA analysis was performed using a "real discount rate" of 7% (0.07/year) as recommended in Reference 20, NUREG/BR-0184. Use of both a 7% and 3% real discount rate in regulatory analysis is specified in Office of Management Budget (OMB) guidance (Reference 25) and in NUREG/BR-0058 (Reference 26). Therefore, a sensitivity analysis was performed using a 3% real discount rate.

In this sensitivity analysis, the real discount rate in the Level 3 PRA model was changed to 3% from 7% and the Phase II analysis was re-performed with the lower interest rate.

The results of this sensitivity analysis are presented in Table 8-1. This sensitivity analysis does not challenge any decisions made regarding the SAMAs.

8.6 ANALYSIS PERIOD

As described in Section 4, calculation of severe accident impacts involves an analysis period term, t_f, which could have been defined as either the period of extended operation (20 years), or the years remaining until the end of facility life (from the time of the SAMA analysis to the end of the period of extended operation) (29 years for Unit 1).

The value used for this term was the period of extended operation (20 years). This sensitivity analysis was performed using the period from the time of the SAMA analysis to the end of the period of extended operation to determine if SAMAs would be potentially cost-beneficial if performed immediately.

In this sensitivity analysis, the analysis period in the calculation of severe accident risk was modified to 29 years and the Phase II analysis was re-performed with the revised analysis period. The cost of additional years of maintenance, surveillance, calibrations, and training were included appropriately in the cost estimates for SAMAs in this Phase II analysis.

The results of this sensitivity analysis are presented in Table 8-1. This sensitivity analysis does not challenge any decisions made regarding the SAMAs.

Table 8-1 BVPS Unit 1 Sensitivity Evaluation

BV1 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
1	Provide additional DC battery capacity.	Extended DC power availability during an SBO.	DC01	$13.9K	$20.1K	$12.4K	$16.5K	$26.7K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
2	Replace lead-acid batteries with fuel cells.	Extended DC power availability during an SBO.	DC01	$13.9K	$20.1K	$12.4K	$16.5K	$26.7K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
4	Improve DC bus load shedding.	Extended DC power availability during an SBO.	DC01	$13.9K	$20.1K	$12.4K	$16.5K	$26.7K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
5	Provide DC bus cross-ties.	Improved availability of DC power system.	DC01	$13.9K	$20.1K	$12.4K	$16.5K	$26.7K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
6	Provide additional DC power to the 120/240V vital AC system.	Increased availability of the 120 V vital AC bus.	DC01	$13.9K	$20.1K	$12.4K	$16.5K	$26.7K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	NOLOSP	$73.7K	$105K	$66.0.K	$86.K	$144K	>$2,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
14	Install a gas turbine generator.	Increased availability of on-site AC power.	NOSBO	$400K	$577K	$357K	$473K	$768K	>$7,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 14 in Unit 2. See report section 7.3.	Cost exceeds benefit.
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	LOCA02	$23.7K	$34.5K	$21.1K	$28.2K	$45.0K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	LOCA02	$23.7K	$34.5K	$21.1K	$28.2K	$45.0K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
28	Add a diverse low pressure injection system.	Improved injection capability.	LOCA03	$2.1K	$3.3K	$1.8K	$2.6K	$3.2K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	LOCA03	$2.1K	$3.3K	$1.8K	$2.6K	$3.2K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	LOCA01	$48.0K	$69.2K	$42.8K	$56.7K	$92.0K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injections systems.	LOCA02	$23.7K	$34.5K	$21.1K	$28.2K	$45.0K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	LOCA01	$48.0K	$69.2K	$42.8K	$56.7K	$92.0K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
48	Cap downstream piping of normally closed component cooling water drain and vent valves.	Reduced frequency of loss of component cooling water initiating events, some of which can be attributed to catastrophic failure of one of the many single isolation valves.	CCW01	<$1K	<$1K	<$1K	<$1K	<$1K	>$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	CHG01	<$1K	<$1K	<$1K	<$1K	<$1K	>$300K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	RCPLOCA2	$1,303K	$1,867K	$1,165K	$1,532K	$2,535K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 8-1 BVPS Unit 1 Sensitivity Evaluation (Cont.)

BVI SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	RCPLOCA2	$1,303K	$1,867K	$1,165K	$1,532K	$2,535K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	CCW01	<$1K	<$1K	<$1K	<$1K	<$1K	>$15K	Screening Procedure Change Value	Not Cost-Beneficial	Cost exceeds benefit.
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	FW01	$37.2K	$55.1K	$32.9K	$44.9K	$67.8K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	INSTAIR1	<$1K	<$1K	<$1K	<$1K	<$1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
94	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.	CONT01	$1,239K	$1,732K	$1,118K	$1,429K	$2,526K	$9,000K	Industry studies (NUREG 1437 supplements), with inflation	Not Cost-Beneficial	Some venting capability currently exists but the post-accident environment could preclude venting. A different vent was considered necessary to assure continued filtering.
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	H2BURN	$30.4K	$42.3K	$27.4K	$34.9K	$62.3K	>$500K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Hydrogen recombiners previously abandoned in place.
98	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.	H2BURN	$30.4K	$42.3K	$27.4K	$34.9K	$62.3K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Hydrogen recombiners previously abandoned in place.
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	LOCA05	$10.7K	$16.2K	$9.4K	$13.2K	$18.6K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Have implemented RI-ISI.
107	Install a redundant containment spray system.	Increased containment heat removal ability.	CONT01	$1,239K	$1,732K	$1,118K	$1,429K	$2,526K	$10,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	LOCA06	$9.9K	$14.0K	$8.9K	$11.5K	$19.7K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	CONT02	$5.8K	$8.2K	$5.2K	$6.7K	$11.4K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	LOCA06	$9.9K	$14.0K	$8.9K	$11.5K	$19.7K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Increased outage frequency/duration.
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	LOCA06	$9.9K	$14.0K	$8.9K	$11.5K	$19.7K	See Note 1.	See Note 1.	Not Cost-Beneficial	The current operating procedures and training meet industry standards and include place-keeping and check-off. No cost beneficial improvements could be identified to either training or procedures that would result in a significant change the HEP. Not cost beneficial.

Table 8-1 BVPS Unit 1 Sensitivity Evaluation (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	NOSGTR	$31.4K	$44.3K	$28.3K	$36.6K	$62.9K	>$3,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
122	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture	Enhanced depressurization capabilities during steam generator tube rupture.	NOSGTR	$31.4K	$44.3K	$28.3K	$36.6K	$62.9K	>$100K	Expert Panel - Screening hardware change value.	Not Cost-Beneficial	Cost exceeds benefit.
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	NOATWS	$13.3K	$21.7K	$11.3K	$17.3K	$18.9K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	NOATWS	$13.3K	$21.7K	$11.3K	$17.3K	$18.9K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	NOATWS	$13.3K	$21.7K	$11.3K	$17.3K	$18.9K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	NOATWS	$13.3K	$21.7K	$11.3K	$17.3K	$18.9K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	NOATWS	$13.3K	$21.7K	$11.3K	$17.3K	$18.9K	>$100K	Expert Panel - 2004 Strategic Action Plan	Not Cost-Beneficial	Cost exceeds benefit.
147	Install digital large break LOCA protection system.	Reduced probability of a large break LOCA (a leak before break).	LOCA05	$10.7K	$16.2K	$9.4K	$13.2K	$18.6K	>$100K	Expert Panel - Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	NOSLB	<$1K	<$1K	<$1K	<$1K	$1.0K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	NOATWS	$13.3K	$21.7K	$11.3K	$17.3K	$18.9K	>$100K	Expert Panel - Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	NOSGTR	$31.4K	$44.3K	$28.3K	$36.6K	$62.9K	$31.4K	Expert Panel	Potentially Cost-Beneficial (because the upper bound sensitivity benefit exceeds the cost)	SAMA is potentially cost beneficial. Loop stop valves are also not designed to close against differential pressure and under accident conditions will not fully seat since hoses must be installed to provide pressure between the seats to fully seat the valve.
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	RCPLOCA2	$1,303K	$1,867K	$1,165K	$1,532K	$2,535K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
166	Provide additional emergency 125V DC battery capability.	Better coping for long term station blackouts	DC01	$13.9K	$20.1K	$12.4K	$16.5K	$26.7K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	DC02	$1,302K	$1,844K	$1,169K	$1,517K	$2,589K	$300K	Expert Panel	Potentially Cost-Beneficial	Potentially cost beneficial
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	FIRE01	$133K	$188K	$119K	$155K	$264K	$80K	Expert Panel	Potentially Cost-Beneficial	Potentially cost beneficial, reference SAMA 143
169	Improve operator performance. Operator starts Aux RW pump given offsite power is available.	One of top 10 operator actions, OPRWA1	HEP1	$3.2K	$4.7K	$2.9K	$3.8K	$6.2K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.

Table 8-1 BVPS Unit 1 Sensitivity Evaluation (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
170	Improve operator performance. Operator starts portable fans & open doors in emergency switchgear room	One of top 10 operator actions. OPRWBV3	HEP2	$93.4K	$132K	$83.8K	$109K	$185K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
171	Improve operator performance. Operator initiates Safety Injection	One of top 10 operator actions. OPROS6	HEP3	$3.0K	$4.3K	$2.7K	$3.5K	$5.9K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
172	Improve operator performance. Operator initiates bleed and feed cooling given failure of prior actions to restore feedwater systems.	One of top 10 operator actions. OPROB2	HEP4	$56.7K	$83.7K	$50.2K	$68.3K	$104K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
173	Improve operator performance. Operator initiates makeup of RWST	One of top 10 operator actions. OPRWM1	HEP5	<$1K	<$1K	<$1K	<$1K	$1.1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
174	Improve operator performance. Operator trips RCPs during loss of CCR.	One of top 10 operator actions. OPROC1	HEP6	$9.8K	$14.1K	$8.8K	$11.6K	$19.0K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
175	Improve operator performance. Operator initiates depressurization of RCS given a general transient initiating event.	One of top 10 operator actions. OPROD2	HEP7	<$1K	<$1K	<$1K	<$1K	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
176	Improve operator performance. Operator initiates depressurization of RCS given a SGTR event.	One of top 10 operator actions. OPROD1	HEP8	<$1K	<$1K	<$1K	<$1K	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
177	Improve operator performance. Operator initiates cooldown and depressurization of RCS given a Small LOCA and failure of HHSI.	One of top 10 operator actions. OPRCD6	HEP9	<$1K	$1.3K	<$1K	<$1K	$1.1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
178	Improve operator performance. Operator aligns hot leg recirculation.	One of top 10 operator actions. OPRLR1	HEP10	<$1K	<$1K	<$1K	<$1K	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
180	Reroute River Water pump power cable	IPEEE issue with CV-3 fire.	SW01	$30.2K	$43.5K	$26.9K	$35.7K	$58.0K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
182	Reroute CCR pump or HHSI suction MOV cables.	IPEEE fire issue for PA-1 fire.	FIRE02	<$1K	<$1K	<$1K	<$1K	<$1K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
183	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for CS-1 fire, NE corner.	FIRE03	$163K	$232K	$147K	$191K	$324K	>$2,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
184	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for NS-1 fire, south wall.	FIRE04	$50.0K	$72.2K	$44.7K	$59.2K	$96.1K	>$2,000	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
186	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	CONT01	$1,239K	$1,732K	$1,118K	$1,429K	$2,526K	>$10,000 K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 190 in Unit 2. See report section 7.3.	Cost exceeds benefit.
187	Increase seismic ruggedness of the ERF Substation batteries. This applies to the battery rack only and not the entire structure.	Increased reliability of the ERF diesel following seismic events	SEISMIC1	$525K	$758K	$469K	$621K	$1,009K	$300K	Expert Panel	Potentially Cost-Beneficial. This SAMA affects both units; see SAMA 186 in Unit 2. See report section 7.3.	Potentially Cost-Beneficial
188	Install a cross-tie between the Unit 1 and Unit 2 RWST.	Increased availability of the RWST for injection.	LOCA04	$729K	$1,047K	$652K	$858K	$1,416K	>$4,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; the Unit 2 affect is too small to be identified as a SAMA. See report section 7.3.	Cost will exceed benefit. BVPS plans to implement this SAMA by using an alternate mitigation strategy that will provide portable pumps that can be used for RWST makeup by the end of 2007.

Table 8-1 BVPS Unit 1 Sensitivity Evaluation (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
189	Provide Diesel backed power for the fuel pool purification pumps and valves used for makeup to the RWST.	Increased availability of the RWST during loss of offsite power and station blackout events.	LOCA04	$729K	$1,047K	$652K	$858K	$1,416K	$200K	Expert panel	Potentially Cost-Beneficial	Potentially cost beneficial. BVPS plans to implement this SAMA by using an alternate mitigation strategy that will provide portable pumps that can be used for RWST makeup by the end of 2007.

Note 1 – The current plant procedures and training meet current industry standards. The benefit calculation results provided in this table are based upon an arbitrary reduction in HEP of a factor of 3 and are provided solely to demonstrate the sensitivity of the model to change in the HEP. There are no additional specific procedure improvements that could be identified that would affect the result of the HEP calculations to this level of reduction. Therefore, it is expected that the idealistic benefits presented in the table are not achievable with procedure improvements only and would require additional hardware modifications. In all cases the costs of hardware and procedure changes would exceed the idealistic benefits presented in the table. These SAMAs are, therefore, screened as Not Cost Beneficial.

9 CONCLUSIONS

As a result of this analysis, the SAMAs identified in Table 9-1 have been identified as potentially cost beneficial, either directly or as a result of the sensitivity analyses. These SAMA are not aging related and are therefore not required to be resolved as part of the relicensing effort. However, since these potential improvements could result in a reduction in public risk, these SAMAs will be entered into the Beaver Valley long-range plan development process for further consideration.

Implementation of SAMA 164 would involve two actions. The first is a procedural change to direct the operators to close the RCS loop stop valves to isolate a steam generator that has had a tube failure. The second involves purchase or manufacture of a gagging device that could be used to close a stuck open steam generator safety valve (i.e., faulted) on the ruptured steam generator prior to core damage in SGTR events.

Implementation of SAMA 167 would involve installation of restraints on the masonry block walls of the emergency switchgear room. This would reduce failures of those walls following seismic events and prevent damage to the four emergency batteries located in the emergency switchgear rooms.

Implementation of SAMA 168 would involve installation of a fire barrier or fire curtain between the four emergency switchgear fans located in the cable spreading room. This would reduce propagation of a fire from one fan to another.

Implementation of SAMA 187 would involve modifications to increase the seismic ruggedness of the battery racks for the ERF diesel generator to be comparable to the emergency batteries, thereby increasing the ERF diesel generator availability following seismic events.. These ERF Substation batteries are not safety related.

Implementation of SAMA 189 involves purchasing a portable pump that can be used to provide makeup to the RWST. BVPS plans to implement this SAMA through an alternate mitigation strategy by the end of 2007.

None of the SAMAs identified in Table 9-1 are aging-related.

Table 9-1 BVPS Unit 1 Potentially Cost Beneficial SAMAs

BV1 SAMA Number	Potential Improvement	Discussion	Additional Discussion
164	Modify emergency procedures to isolate a faulted SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	
187	Increase seismic ruggedness of the ERF Substation batteries. This applies to the battery rack only and not the entire structure.	Increased reliability of the ERF diesel following seismic events	
189	Provide Diesel backed power for the fuel pool purification pumps and valves used for makeup to the RWST.	Increased availability of the RWST during loss of offsite power and station blackout events.	BVPS plans to implement this SAMA through alternate mitigation strategies that provide portable pumps that can be used for RWST makeup by the end of 2007.

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APPENDIX A – PRA RUNS FOR SELECTED SAMA CASES

Explanation of Appendix A Contents

This appendix describes each of the SAMA evaluation cases. An evaluation case is an evaluation of plant risk using a plant PRA model that considers implementation of the evaluated SAMA. The case-specific plant configuration is defined as the plant in its baseline configuration with the model modified to represent the plant after the implementation of a particular SAMA. As indicated in the main report, these model changes were performed in a manner expected to bound the change in risk that would actually be expected if the SAMA were implemented. This approach was taken because the actual designs for the SAMAs have not been developed.

Each analysis case is described in the following pages. Each case description contains a description of the physical change that the case represents along with a description of the SAMAs that are being evaluated by this specific case.

The PDS frequencies calculated as a result of the PRA model quantification for each SAMA case is presented in Table A-8.

Case INSTAIR1

Description: This case is used to determine the benefit of replacing the air compressors. For the purposes of the analysis, a single bounding condition was performed, which assumed the station and containment instrument air systems do not fail.

Case NOATWS

Description: This case is used to determine the benefit of eliminating all Anticipated Transient Without Scram (ATWS) events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.

Case NOSGTR

Description: This case is used to determine the benefit of eliminating all Steam Generator Tube Rupture (SGTR) events. This allows evaluation of various possible improvements that could reduce the risk associated with SGTR events. For the purposes of this analysis, a single bounding analysis was performed which assumed that SGTR events do not occur.

Case RCPLOCA

Description: This case is used to determine the benefit of eliminating all Reactor Coolant Pump (RCP) seal loss of coolant accident (LOCA) events. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.

Case NOLOSP

Description: This case is used to determine the benefit of eliminating all Loss of Offsite Power (LOSP) events, both as the initiating event and subsequent to a different initiating event. This allows evaluation of various possible improvements that could reduce the risk associated with LOSP events. For the purposes of the analysis, a single bounding analysis was performed which assumed that LOSP events do not occur, both as an initiating event and subsequent to a different initiating event.

Case NOSBO

Description: This case is used to determine the benefit of eliminating all Station Blackout (SBO) events. This allows evaluation of possible improvements related to SBO sequences. For the purpose of the analysis, a single bounding analysis is performed that assumes the emergency AC power supplies do not fail.

Case NOSLB

Description: This case is used to determine the benefit of installing secondary side guard pipes to the Main Steam Isolation Valves (MSIVs). This would prevent secondary side depressurization should a Steam Line Break (SLB) occur upstream of the MSIVs. For the purposes of the analysis, a single bounding analysis was performed which assumed that no SLB inside containment events occur.

HEP Cases

A description of the Operator Actions can be found in the Beaver Valley Unit 1 Probabilistic Risk Assessment Update Report (Reference 27).

All HEP cases are performed using the red button feature of the RISKMAN code; this implies the re-creation of a set of MFFs by the RISKMAN code.

Case HEP1

Description: The probability of basic event OPRWA1, Operator starts Aux RW pump given offsite power is available, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP2

Description: The probability of basic event OPRBV3, Operator starts portable fans & open doors in Emer. Switchgear, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP3

Description: The probability of basic event OPROS6, Operator initiates Safety Injection, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP4

Description: The probability of basic event OPROB2, Operator initiates bleed and feed cooling given failure of prior actions to restore feedwater systems, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP5

Description: The probability of basic event OPRWM1, Operator initiates makeup to RWST, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP6

Description: The probability of basic event OPROC1, Operator trips RCPs during loss of CCR, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP7

Description: The probability of basic event OPROD2, Operator initiates depressurization of RCS given a General Transient initiating event, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP8

Description: The probability of basic event OPROD1, Operator initiates depressurization of RCS given a SGTR initiating event, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP9

Description: The probability of basic event OPRCD6, Operator initiates cooldown and depressurization of RCS given a Small LOCA and failure of HHSI, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP10

Description: The probability of basic event OPRLR1, Operator aligns hot leg recirculation, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case LOCA01

Description: Assume small LOCA events do not occur. This case is used to determine the benefit of eliminating all small LOCA events.

Case LOCA02

Description: Assume the high pressure injection system does not fail. This case is used to determine the benefit of improvements to the High Pressure Injection Systems.

Case LOCA03

Description: Assume failures of the low pressure injection system do not occur. This case is used to determine the benefit of improving the Low Pressure Injection Systems.

Case LOCA04

Description: This case assumes that the RWST cannot be depleted. This case is used to determine the impact of refilling or backup of the water supply for the RWST.

Case LOCA05

Description: Assume that piping system LOCAs do not occur. This case is used to determine the benefit of eliminating all LOCA events related to piping failure (no change to non-piping failure is considered).

Case LOCA06

Description: Assume ISLOCA events do not occur. This case is used to determine the benefit of eliminating all ISLOCA events.

Case DC1

Description: Assume the DC power systems do not fail or deplete. This case is used to determine the impact of the improvement in the DC power system.

Case CHG01

Description: Assume the charging pumps are not dependent on cooling water. This case is used to determine the benefit of removing the charging pumps dependency on cooling water.

Case SW01

Description: Assume the service water pumps are not dependent on DC power. This case is used to determine the benefit of enhancing the DC control power to the service water pumps.

Case CCW01

Description: This case is used to determine the benefit of improvement to the CCW system by assuming that CCW pumps do not fail.

Case FW01

Description: Eliminate loss of feedwater initiating events. This case is used to determine the benefit of improvements to the feedwater and feedwater control systems.

Case RCPLOCA2

Description: This case is used to determine the benefit of eliminating all RCP seal LOCA events except those associated with seismic events with a PGA greater than 0.35g. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events. RCPLOCA2 (identified as RCPLOCA in the attached *Phase3SAMAMethod.doc* file) is actually an extension of the RCPLOCA case run during Phase I.

Case CONT01

Description: Assume that the containment does not fail due to overpressurization. This case is used to determine the benefit of eliminating all containment failures due to overpressurization.

Case H2BURN

Description: Assume hydrogen burns and detonations do not occur. This case is used to determine the benefit of eliminating all hydrogen ignition and burns.

Case CONT02

Description: Assume there are no failures of containment isolation. This case is used to determine the benefit of eliminating all containment isolation failures.

Case FIRE01

Description: Eliminate the cable spreading room fire that fails switchgear ventilation fans. This case is used to determine the benefit of eliminating all fires that impact the fans in the cable spreading room.

Case DC2

Description: Assume a seismic event does not cause the block wall to fail which in turn fails the batteries. This case is used to determine the benefit of eliminating the seismic failure of the 125VDC battery room block walls.

Case FIRE02

Description: This case eliminates the fires in zone PA-1E causing failure of component cooling water and of seal injection. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE03

Description: This case eliminates the fires in zone CS-1, northeast corner, that cause failure of both river water pumps and both auxiliary river water pumps. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE04

Description: This case eliminates the fires in zone NS-1 that cause total loss of river water. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case SEISMIC1

Description: This case reduces the failure of the ERF Substation batteries due to seismic events (by setting the ERF Substation battery seismic capacity equivalent to the Unit 2 125V DC Emergency battery capacity). This case is used to evaluate improvements that would strengthen the ERF Substation battery racks.

Cases SGTR2, SGTR3, and SGTR4

Description: The SG sensitivity cases were performed assuming that the operator action to close the RCS loop stop valves or to gag closed the stuck-open SG SV would only have a 50% probability of success, as opposed to the 100% success probability assumed in the NOSGTR maximum benefit case. To perform the SG sensitivity cases, the sum of SGTR release bin frequencies were divided by the single SGTR initiating event frequency (1.6059E-03) to obtain the SGTR conditional core damage probabilities for each release bin. The following describes how these SGTR release bin frequency sums and conditional release bin frequencies were applied to each sensitivity case.

For the SGTR2 case, where the operators gag a stuck-open SV, only the unscrubbed containment bypass release bin frequency (BV18) would be impacted. Since the assumed operator action to gag closed the stuck-open SG SV has a 50% probability of success, the SGTR BV18 release bin frequency was multiplied by 0.5. However, since the total CDF from SGTRs would not change from performing this action, the other 50% of the BV18 release bin frequency was added to the scrubbed small release bin frequency (BV20). The remaining SGTR release bin frequency sums remained unchanged. These new SGTR bin frequencies were then added to the NOSGTR release bin frequencies to obtain the SGTR2 sensitivity case release bin frequencies.

For the SGTR3 case, where the operators close the RCS loop stop valves, all of the SGTR release bin frequencies are impacted, since this action would essentially terminate the SGTR. Since the assumed operator action to perform this action has a 50% probability of success, the SGTR initiating event frequency was multiplied by 0.5. This new initiating event frequency (8.0295E-04) was then multiplied by each of the SGTR conditional release bin probabilities. The resultant new SGTR bin frequencies were then added to the NOSGTR release bin frequencies to obtain the SGTR3 sensitivity case release bin frequencies.

For the SGTR4 case, where the operators close the RCS loop stop valves and gag a stuck-open SV, all of the SGTR release bin frequencies are impacted, since this action would essentially terminate the SGTR. Since the assumed operator action to perform this action has a 50% probability of success, the SGTR initiating event frequency was multiplied by 0.5. This new initiating event frequency (8.0295E-04) was then multiplied by each of the SGTR conditional release bin probabilities to obtain revised SGTR bin frequencies. Additionally, the unscrubbed containment bypass release bin frequency (BV18) would be reduced by a 50% probability of success for terminating the unscrubbed containment bypass release. Therefore, the revised SGTR BV18 release bin frequency was further reduced by multiplying it by 0.5, and the other 50% of the revised BV18 release bin frequency was added to the revised scrubbed small release bin frequency (BV20). These new SGTR bin frequencies were then added to the NOSGTR release bin frequencies to obtain the SGTR4 sensitivity case release bin frequencies.

Table A-8
BVPS Unit 1 Release Category Frequency Results Obtained From SAMA Cases

BV1 RELEASE CATEGORIES	BASE	INSTAIR1	NOATWS	NOSGTR	RCPLOCA	NOLOSP	NOSBO	NOSLB	HEP1	HEP2	HEP3
Intact	1.00E-06	1.00E-06	6.51E-07	1.00E-06	9.66E-07	9.91E-07	9.82E-07	1.00E-06	1.00E-06	1.00E-06	1.00E-06
ECF-VSEQ	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	3.89E-09	2.04E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08
ECF-SGTR	5.26E-08	5.25E-08	4.52E-08	0.00E+00	5.26E-08	1.38E-08	5.29E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08
ECF-DCH	1.56E-09	1.57E-09	1.56E-09	1.56E-09	7.60E-10	1.53E-09	1.16E-09	1.56E-09	1.56E-09	1.56E-09	1.56E-09
SECF-VSEQ	7.93E-06	7.93E-06	7.93E-06	7.92E-06	8.12E-09	7.91E-06	7.91E-06	7.93E-06	7.93E-06	7.70E-06	7.93E-06
SECF-LOCI	1.27E-07	1.27E-07	1.27E-07	1.27E-07	4.21E-06	1.26E-07	1.23E-07	1.27E-07	1.27E-07	1.27E-07	1.22E-07
SECF-BV5	6.56E-09	6.56E-09	6.56E-09	6.56E-09	3.34E-06	6.50E-09	6.19E-09	6.56E-09	6.56E-09	6.56E-09	3.77E-09
LATE-LARGE	1.33E-08	1.33E-08	8.69E-09	1.33E-08	1.33E-08	1.33E-08	1.32E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08
LATE-SMALL	9.74E-06	9.75E-06	9.74E-06	9.74E-06	2.41E-06	9.54E-06	7.58E-06	9.74E-06	9.73E-06	9.74E-06	9.74E-06
LATE-H2BURN	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
LATE-BMMT	5.51E-07	5.51E-07	5.32E-07	5.51E-07	5.39E-07	5.46E-07	5.36E-07	5.50E-07	5.51E-07	5.51E-07	5.50E-07
CDF	1.94E-05	1.94E-05	1.91E-05	1.94E-05	1.16E-05	1.92E-05	1.72E-05	1.94E-05	1.94E-05	1.92E-05	1.94E-05

Table A-1
BVPS Unit 1 Release Category Frequency Results Obtained From SAMA Cases (Cont.)

BV1 RELEASE CATEGORIES	HEP4	HEP5	HEP6	HEP7	HEP8	HEP9	HEP10	LOCA01	LOCA02	LOCA03
Intact	8.33E-07	1.00E-06	1.00E-06	1.00E-06	1.00E-06	9.84E-07	1.00E-06	1.00E-06	9.81E-07	9.73E-07
ECF-VSEQ	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.01E-08	2.05E-08
ECF-SGTR	5.26E-08	5.16E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.18E-08	5.27E-08
ECF-DCH	1.49E-09	1.56E-09	1.56E-09	1.56E-09	1.56E-09	1.56E-09	1.56E-09	1.60E-09	1.54E-09	1.56E-09
SECF-VSEQ	7.93E-06	7.93E-06	7.92E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06
SECF-LOCI	5.49E-08	1.27E-07	1.27E-07	1.27E-07	1.27E-07	1.27E-07	1.27E-07	1.27E-07	1.25E-07	1.27E-07
SECF-BV5	6.14E-09	6.56E-09	6.56E-09	6.56E-09	6.56E-09	6.56E-09	6.56E-09	6.52E-09	6.56E-09	6.57E-09
LATE-LARGE	1.09E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.30E-08	1.30E-08
LATE-SMALL	9.74E-06	9.74E-06	9.70E-06	9.74E-06	9.74E-06	9.74E-06	9.74E-06	9.48E-06	9.64E-06	9.74E-06
LATE-H2BURN	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
LATE-BMMT	2.52E-07	5.51E-07	5.50E-07	5.50E-07	5.50E-07	5.46E-07	5.50E-07	5.45E-07	5.24E-07	5.30E-07
CDF	1.89E-05	1.94E-05	1.94E-05	1.94E-05	1.94E-05	1.94E-05	1.94E-05	1.92E-05	1.93E-05	1.94E-05

Table A-1
BVPS Unit 1 Release Category Frequency Results Obtained From SAMA Cases (Cont.)

BV1 RELEASE CATEGORIES	LOCA04	LOCA05	LOCA06	DC1	CHG01	SW01	CCW01	FW01	RCPLOCA2	CONTO1
Intact	1.02E-06	9.11E-07	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	8.13E-07	9.66E-07	5.51E-06
ECF-VSEQ	2.81E-09	2.05E-08	0.00E+00	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08
ECF-SGTR	3.09E-09	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08
ECF-DCH	1.56E-09	1.56E-09	1.56E-09	1.55E-09	1.56E-09	1.52E-09	1.56E-09	1.55E-09	1.08E-09	8.87E-11
SECF-VSEQ	7.47E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06	5.45E-06	7.93E-06
SECF-LOCI	1.26E-07	1.26E-07	1.27E-07	1.27E-07	1.27E-07	1.27E-07	1.27E-07	1.23E-07	1.30E-06	1.14E-08
SECF-BV5	6.55E-09	6.56E-09	6.56E-09	6.56E-09	6.56E-09	6.56E-09	6.56E-09	5.88E-09	8.23E-07	6.37E-09
LATE-LARGE	1.34E-08	1.20E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.08E-08	1.33E-08	0.00E+00
LATE-SMALL	6.94E-06	9.71E-06	9.74E-06	9.67E-06	9.74E-06	9.58E-06	9.74E-06	9.58E-06	4.59E-06	0.00E+00
LATE-H2BURN	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
LATE-BMMT	5.35E-07	5.26E-07	5.51E-07	5.51E-07	5.50E-07	5.51E-07	5.50E-07	5.30E-07	5.39E-07	5.92E-06
CDF	1.61E-05	1.93E-05	1.94E-05	1.94E-05	1.94E-05	1.93E-05	1.94E-05	1.91E-05	1.38E-05	1.94E-05

Table A-1
BVPS Unit 1 Release Category Frequency Results Obtained From SAMA Cases (Cont.)

BV1 RELEASE CATEGORIES	H2BURN	CONT02	FIRE01	DC2	FIRE02	FIRE03	FIRE04	SEISMIC1
Intact	1.01E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
ECF-VSEQ	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08
ECF-SGTR	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08
ECF-DCH	1.55E-09	1.55E-09	1.56E-09	1.74E-09	1.56E-09	1.56E-09	1.56E-09	9.47E-10
SECF-VSEQ	7.93E-06	7.93E-06	7.60E-06	4.60E-06	7.93E-06	7.53E-06	7.93E-06	7.91E-06
SECF-LOCI	1.25E-08	1.16E-07	1.27E-07	1.26E-07	1.27E-07	1.27E-07	1.27E-07	1.26E-07
SECF-BV5	6.62E-09	1.90E-10	6.56E-09	5.99E-09	6.56E-09	6.56E-09	6.56E-09	5.90E-09
LATE-LARGE	0.00E+00	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08
LATE-SMALL	9.75E-06	9.74E-06	9.74E-06	1.00E-05	9.74E-06	9.74E-06	9.47E-06	6.87E-06
LATE-H2BURN	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
LATE-BMMT	6.74E-07	5.51E-07	5.51E-07	5.51E-07	5.50E-07	5.51E-07	5.51E-07	5.50E-07
CDF	1.94E-05	1.94E-05	1.91E-05	1.64E-05	1.94E-05	1.90E-05	1.92E-05	1.65E-05

ATTACHMENT C-2 BEAVER VALLEY UNIT 2 SAMA ANALYSIS

EXECUTIVE SUMMARY

This report provides an analysis of the Severe Accident Mitigation Alternatives (SAMAs) that were identified for consideration by the Beaver Valley Power Station Unit 2. This analysis was conducted on a cost/benefit basis. The benefit results are contained in Section 4 of this report. Candidate SAMAs that do not have benefit evaluations have been eliminated from further consideration for any of the following reasons:

- The cost is considered excessive compared with benefits.
- The improvement is not applicable to Beaver Valley Unit 2.
- The improvement has already been implemented at Beaver Valley Unit 2 or the intent of the improvement is met for Beaver Valley Unit 2.

After eliminating a portion of the SAMAs for the preceding reasons, the remaining SAMAs are evaluated from a cost-benefit perspective. In general, the analysis approach examines the SAMAs from a bounding analysis approach to determine whether the expected cost would exceed a conservative approximation of the actual expected benefit. In most cases, therefore, a detailed risk evaluation in which a specific modification/procedure change is evaluated would indicate a smaller benefit than calculated in this evaluation.

Major insights from this benefit evaluation process included the following:

If all core damage risk is eliminated, then the benefit in dollars over 20 years is $5,093,366.

- The largest contributors to the total benefit estimate are from offsite dose and offsite property damage.
- A large number of SAMAs had already been addressed by existing plant features, modifications to improve the plant, existing procedures, or procedure changes to enhance human performance.

The following SAMAs have been identified as potentially cost-beneficial.

BV2 SAMA Number	Potential Improvement	Discussion	Additional Discussion
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	This would provide a system similar to the dedicated AFW pump present at Unit 1.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	

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1 INTRODUCTION

1.1 PURPOSE

The purpose of the analysis is to identify SAMA candidates at the Beaver Valley Power Station Unit 2 that have the potential to reduce severe accident risk and to determine whether implementation of the individual SAMA candidate would be cost beneficial. NRC license renewal environmental regulations require SAMA evaluation.

1.2 REQUIREMENTS

- 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...."

2 METHOD

The SAMA analysis approach applied in the Beaver Valley assessment consists of the following steps.

- **Determine Severe Accident Risk**

  Level 1 and 2 Probabilistic Risk Assessment (PRA) Model
  The Beaver Valley Unit 2 PRA model (Section 3.1 – 3.2) was used as input to the consolidated Beaver Valley Unit 1/2 Level 3 PRA analysis (Section 3.4).

  The PRA results include the risk from internal and external events. The external hazards evaluated in the PRA are internal fires and seismic events only. High winds and tornadoes, external floods, and transportation and nearby facility accidents are not included in the results since they were screened from the IPEEE submittal because their individual CDF fell below the cutoff criteria of 1.0E-06 per year.

Level 3 PRA Analysis
The Level 1 and 2 PRA output and site-specific meteorology, demographic, land use, and emergency response data was used as input for the consolidated Beaver Valley Unit 1/2 Level 3 PRA (Section 3). This combined model was used to estimate the severe accident risk 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 to estimate the cost of severe accident risk were used throughout this analysis. In this step these techniques were used to estimate the maximum benefit that a SAMA could achieve if it eliminated all risk i.e., the maximum benefit (Section 4).

- **SAMA Identification**

In this step potential SAMA candidates (plant enhancements that reduce the likelihood of core damage and/or reduce releases from containment) were identified by Beaver Valley Unit 2 (BVPS-2) plant staff, from the PRA model, Individual Plant Examination (IPE) and IPE – External Events (IPEEE) recommendations, and industry documentation (Section 5). This process included consideration of the PRA importance analysis because it has been demonstrated by past SAMA analyses that 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.

- **Preliminary Screening (Phase I SAMA Analysis)**

Because many of the SAMA candidates identified in the previous step are from the industry, it was necessary to screen out SAMA candidates that were not applicable to the BVPS-2 design, candidates that had already been implemented or whose benefits have been achieved at the plant using other means, and candidates whose roughly estimated cost exceeded the maximum benefit. Additionally, PRA insights (specifically, importance measures) were used directly to screen SAMA candidates that did not address significant contributors to risk in this phase (Section 6).

- **Final Screening (Phase II SAMA Analysis)**

In this step of the analysis the benefit of severe accident risk reduction was estimated for each of the remaining SAMA candidates and compared to an implementation cost estimate to determine net cost-benefit (Section 7). The benefit associated with each SAMA was determined by the reduction in severe accident risk from the baseline derived by modifying the plant model to represent the plant after implementing the candidate. In general, the modeling approach used was a bounding approach to first determine a bounding value of the benefit. If this benefit was determined to be smaller that the expected cost, no further modeling detail was necessary. If the benefit was found to be greater that the estimated cost, the modeling was refined to remove conservatism in the modeling and a less conservative benefit was determined for comparison with the estimated cost.

Similarly, the initial cost estimate used in this analysis was the input from the expert panel (plant staff familiar with design, construction, operation, training and maintenance) meeting. All costs associated with a SAMA were considered, including design, engineering, safety analysis, installation, and long-term maintenance, calibrations, training, etc. If the estimated cost was found to be close to the estimated benefit, then first the benefit evaluation was refined to remove conservatism and if the estimated cost and benefit were still close, then the cost estimate was refined to assure that both the benefit calculation and the cost estimate are sufficiently accurate to justify further decision making based upon the estimates.

- **Sensitivity Analysis**

The next step in the SAMA analysis process involved evaluation on the impact of changes in SAMA analysis assumptions and uncertainties on the cost-benefit analysis (Section 8).

- **Identify Conclusions**

The final step involved summarizing the results and conclusions (Section 9).

3 SEVERE ACCIDENT RISK

The BVPS PRA models describe the results of the first two levels of the BVPS probabilistic risk assessment for the plant's two units. These levels are defined as follows: Level 1 determines CDFs based on system analyses and human reliability assessments; Level 2 evaluates the impact of severe accident phenomena on radiological releases and quantifies the condition of the containment and the characteristics of the release of fission products to the environment. The BVPS models use PRA techniques to:

- Develop an understanding of severe accident behavior;
- Understand the most likely severe accident consequences;

- Gain a quantitative understanding of the overall probabilities of core damage and fission product releases; and
- Evaluate hardware and procedure changes to assess the overall probabilities of core damage and fission product releases.

The Unit 1 and Unit 2 PRAs were initiated in response to Generic Letter 88-20, which resulted in IPE and IPE for External Events (IPEEE) analyses. The current model for each Unit (BV1REV4 for Unit 1 and BV2REV4 for Unit 2) is a consolidated Level 1 / Level 2 model including both internal and external initiating events (i.e., consolidates IPE and IPEEE studies into a single, Unit-specific PRA model) for power operation. This means that severe accident sequences have been developed from internal and external initiated events, including internal floods, internal fires, and seismic events.

The PRA models used in this analysis to calculate severe accident risk due to Unit 2 are described in this section. The Unit 2 Level 1 PRA model (internal and external), the Unit 2 Level 2 PRA model, Unit 2 PRA model review history, and the consolidated Unit 1/2 Level 3 PRA model, are described in Section 3.1, 3.2 and 3.4. Include results of the severe accident risk calculation as shown in Section 3.5.

3.1 LEVEL 1 PRA MODEL

3.1.1 Internal Events

3.1.1.1 Description of Level 1 Internal Events PRA Model

The US Nuclear Regulatory Commission (NRC) issued Generic Letter No. 88-20, in December 1988, which requested each plant to perform an individual plant examination of internal events (IPE) to identify any vulnerabilities. In response, Duquesne Light Company (DLC) submitted an IPE report (Reference 4) using a probabilistic risk assessment (PRA) approach for Beaver Valley Power Station Unit 2 (BVPS-2) in March 1992 that examined risk from internal events, including internal flooding.

The updated PRA model, used to determine CDF, is the BV2REV4 model. This model contains the Level 1 model for internal initiating events. The software used in the update process was RISKMAN. A Level 1 PRA presents the risk (that is, what can go wrong and what is the likelihood?) associated with core damage. For the updated PRA, core damage is defined as the uncovery and heatup of the reactor core to the point where prolonged cladding oxidation and severe fuel damage is anticipated. This condition is expected whenever the core exit temperatures exceed 1,200°F and the core peak nodal temperatures exceed 1,800°F.

The Beaver Valley Unit 2 Internal Events CDF is calculated to be 9.53E-06 /year. The fault tree method of quantification is binary decision diagram quantification, which provides an exact solution for split fraction values. The event tree quantification was calculated using a truncation cutoff frequency of 1.0E-14, or more than 8 orders of magnitude below the baseline CDF. The results of the CDF quantification of risk from internal events is summarized in Table 3.1.1.1-1 (Initiating Event Contribution to core damage) Table 3.1.1.1-2 (Basic Event Importance) and Table 3.1.1.1-3 (Component Importance). Contribution to internal events CDF from ATWS and SBO sequences is presented below for information purposes.

	Contribution to CDF (/year)
ATWS	1.57E-07
SBO	8.14E-07

The original PRA model (IPE submittal) was based on the BVPS-2 plant configuration circa 1988 and was calculated using a plant specific database that included equipment failures and maintenance history from startup until the end of 1988. During the IPEEE submittal (Reference 5), the PRA had a "freeze date" of December 31, 1996 for both plant configuration and component failure data. The results presented in this report are based on an updated PRA model (BV2REV4), which has a "freeze date" of November 13, 2006 for the plant configuration, and a "freeze date" of December 31, 2005 for component failure data and internal initiating events data. Equipment unavailabilities were based on Maintenance Rule availability history from June 1, 2000 to December 31, 2005. This updated PRA model was also revised to include modeling enhancements.

Table 3.1.1.1-1: BV2REV4 Dominant Initiating Event Contribution to Internal Core Damage

Initiator	Description	Initiating Event Frequency	Contribution to Internal CDF	Percent of Internal CDF	Cumulative Percent of Internal CDF
BPX	Loss of Emergency 4160V AC Purple	1.40E-02	2.02E-06	21.2%	21.2%
AOX	Loss of Emergency 4160V AC Orange	1.43E-02	1.78E-06	18.7%	39.9%
LOSPE	Loss of Offsite Power - Extreme Weather Related	2.24E-03	6.61E-07	6.9%	46.8%
CVFLF	Cable Vault Flood from Fire Water	1.46E-04	6.07E-07	6.4%	53.2%
WCX	Loss of Service Water Trains A & B	2.61E-06	5.29E-07	5.5%	58.7%
SGFL2	Both Safeguards Area Flood, Nonisolated	4.88E-05	3.52E-07	3.7%	62.4%
ICX	Loss of Containment Instrument Air	8.59E-02	2.94E-07	3.1%	65.5%
VSX	V-Sequence Initiating Event	2.80E-07	2.80E-07	2.9%	68.5%
ELOCA	Excessive Loss of Coolant Accident	2.66E-07	2.66E-07	2.8%	71.2%
DPX	Loss of Emergency 125V DC Purple	1.03E-02	2.64E-07	2.8%	74.0%
DOX	Loss of Emergency 125V DC Orange	1.03E-02	2.53E-07	2.7%	76.7%
TTRIP	Turbine/Generator Trip	4.49E-01	2.20E-07	2.3%	79.0%
WBXX	Loss of Service Water Train B	4.72E-03	1.53E-07	1.6%	80.6%
RTRIP	Reactor Trip	2.96E-01	1.34E-07	1.4%	82.0%
WAX	Loss of Service Water Train A	4.15E-03	1.30E-07	1.3%	83.4%
SGTRC	Loop C Steam Generator Tube Rupture	1.61E-03	1.23E-07	1.3%	84.7%
SGTRA	Loop A Steam Generator Tube Rupture	1.61E-03	1.23E-07	1.3%	85.9%
SGTRB	Loop B Steam Generator Tube Rupture	1.61E-03	1.23E-07	1.3%	87.2%
PLMFW	Partial Loss of Main Feedwater	2.44E-01	1.11E-07	1.2%	88.4%
SGFL1A	S. Safeguards Train A Area Flood, Isolated	3.65E-04	1.11E-07	1.2%	89.6%
LOSPG	Loss of Offsite Power - Grid Related	1.33E-02	8.01E-08	0.8%	90.4%

Table 3.1.1.1-2 BV2REV4 Top 10 Basic Events by Risk Reduction Worth (Internal Events)				
Rank	**Basic Event Name**	**Basic Event Description**	**RRW***	**Applicable SAMA**
1	BSOR480VUS29	Bus 480VUS-2-9 Fails During Operation	1.12E+00	AC Power SAMAs
2	BSOR4KVS2DF	4160V Bus 4KVS-2DF Fails During Operation	1.12E+00	AC Power SAMAs
3	BSOR480VUS28	Bus 480VUS-2-8 Fails During Operation	1.10E+00	AC Power SAMAs
4	BSOR4KVS2AE	4160V Bus 4KVS-2AE Fails During Operation	1.10E+00	AC Power SAMAs
5	PTSR2FWEP22	Turbine Drive Pump 2FWE-P22 Fails to Run	1.10E+00	SAMA 78
6	CBFC4KVS2D2D7	SSST-2B Incoming BKR ACB-342B (4KVS-2D-2D7) Fails to Close	1.06E+00	AC Power SAMAs
7	CBFC4KVS2A2A4	SSST-2A Incoming BKR ACB-42A (4KVS-2A-2A4) Fails to Close	1.06E+00	AC Power SAMAs
8	XRORTRF29P	480VUS Transformer TRF-2-9P Fails During Operation	1.05E+00	AC Power SAMAs
9	OGXXXX	Offsite Grid Fails Following Non-LOSP Initiator	1.05E+00	AC Power SAMAs
10	[FNOR2HVWFN257A FNOR2HVWFN257B FNOR2HVWFN257C]	Common Cause Failure of Cubicle Ventilation Fans Fail to Run	1.05E+00	HVAC SAMAs
* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship: RRW = 1 / (1 - FV)				

Table 3.1.1.1-3 BV2REV4 Top 10 Components by Risk Reduction Worth w/o Common Cause (Internal Events)				
Rank	**Component Name**	**Component Description**	**RRW***	**Applicable SAMA**
1	480VUS-2-9	Emergency 480V AC Bus 480VUS-2-9	1.12E+00	AC Power SAMAs
2	4KVS-2DF	4160V AC Emergency Bus 2DF	1.12E+00	AC Power SAMAs
3	2FWE-P22	Turbine Driven Auxiliary Feedwater Pump	1.11E+00	SAMA 79
4	480VUS-2-8	Emergency 480V AC Bus 480VUS-2-8	1.11E+00	AC Power SAMAs
5	4KVS-2AE	4160V AC Emergency Bus 2AE	1.11E+00	AC Power SAMAs
6	2EGS-EG2-1	Emergency Diesel Generator 2-1	1.08E+00	AC Power SAMAs
7	2EGS-EG2-2	Emergency Diesel Generator 2-2	1.08E+00	AC Power SAMAs
8	TRF-2-9P	Transformer For Substation 2-9	1.07E+00	AC Power SAMAs
9	4KVS-2D-2D7	Incoming Supply Feed Bkr from TR-2B for Bus 2D (ACB-342B)	1.07E+00	AC Power SAMAs
10	TRF-2-8N	Transformer for Substation 2-8	1.06E+00	AC Power SAMAs

* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship:
RRW = 1 / (1 - FV)

3.1.1.2 Level 1 PRA Model Changes since IPE Submittal

The major Level 1 changes incorporated into each revision of the Beaver Valley Unit 2 PRA model are discussed below. The individual effect on CDF by incorporating each of these changes has not been analyzed. However, each change is listed in order of expected importance, with the top change being the most important.

BVPS-2 PRA Model History							
PRA Model	**Rev.**	**Date**	**Internal**		**Total**		**Comments**
			CDF	**LERF**	**CDF**	**LERF**	
BV2	0	03/17/92	1.90E-04	8.44E-06	-	-	IPE Model
BV2REV1	1	09/30/97	5.96E-05	9.05E-07	7.54E-05	1.14E-06	IPEEE model
BV2REV2	2	10/31/97	5.96E-05	9.05E-07	7.54E-05	1.14E-06	Integrated Level 1 and Level 2 models
BV2REV3A	3A	01/31/02	8.50E-06	5.10E-07	1.60E-05	5.10E-07	NEI 00-02 Peer Reviewed
BV2REV3B	3B	05/31/03	2.00E-05	1.14E-06	3.43E-05	1.14E-06	NEI 00-02 Peer Review A/B F&Os addressed
BV2REV4	4	04/02/07	9.53E-06	4.06E-07	2.40E-05	4.09E-07	ACC/EPU Model

<u>Beaver Valley Unit 2 Revision 0</u>

This revision represents the base case IPE quantification and resulted in a core damage frequency of <u>1.90E-04 / year</u> for internal events.

<u>Beaver Valley Unit 2 Revision 1</u>

Beaver Valley Unit 2 Revision 1 served as the baseline risk model for the IPEEE and included implementation of IPE vulnerability enhancements. This model was made with the following model modifications. The changes resulted in an internal events core damage frequency of <u>5.96E-05 / year</u>.

- The updated model gave credit for the operators to depressurize the RCS during small break LOCAs, so that a low head safety injection pump can provide makeup and core cooling, given the failure of the high head safety injection system. The CDF definition was also changed so that both core exit temperatures exceeded 1,200°F and the core peak nodal temperatures exceeded 1,800°F must be present.
- The revised frequency included consideration of the station cross-tie connecting the 4KV normal buses of Beaver Valley Units 1 and 2. The cross-tie model permits credit for the Unit 1 emergency diesel generators, if available, to power either Unit 2

emergency AC bus 2AE or 2DF, given the failure of both Unit 2 emergency diesel generators and a loss of offsite power.

- An analysis was performed based on actual test data to determine the room heatup rate for the Unit 2 emergency switchgear area following the loss of all ventilation. The results of this analysis concluded that the area would not heat up past the equipment qualification limit during a 24 hour period. Therefore, based on this analysis, Top Event "BV", which contributed 17.1% to the IPE CDF, was eliminated from the updated BVPS-2 model.
- The Unit 2 ATWS model was also revised to give full pressure relief capacity credit for each of the 3 PORVs to reduce the unfavorable exposure time and models all possible PORV alignments.

Beaver Valley Unit 2 Revision 2

This revision simply integrated the Beaver Valley Unit 2 Revision 1, Level 1 and Level 2 PRA models into a single PRA model. The internal events core damage frequency remained at 5.96E-05 / year.

Beaver Valley Unit 2 Revision 3A

Beaver Valley Unit 2 Revision 3A was an interim PRA model that was used in the NEI 00-02 PRA Peer Review process. This revision was made with the following model modifications. The changes resulted in an internal events core damage frequency of 8.50E-06 / year.

- The updated model used the latest industry methodology for determining reactor coolant pump (RCP) seal LOCAs. This methodology is based on Westinghouse WCAP-15603, Rev. 0 (Reference 21); however, it was slightly modified to account for the NRC's preliminary comments reviewing the WCAP. This modification used a number 1 seal popping-and-binding failure probability P(PB1) of 0.025 (which is the same as the Brookhaven Model) instead of 0.0125. With this new RCP seal LOCA model there was a 78-percent probability that the seal leakage would not exceed 21 gpm per RCP during the loss of all seal cooling condition, which accounts for the installed high-temperature O-rings on all three RCPs.
- The revised RCP seal LOCA frequency also included plant specific thermal hydraulic analyses performed with MAAP 4.0.4, which now accounts for sequences that do not go to core melt during a 24 hour period, given that AFW is available. These analyses were performed for both station blackout and loss of all service water scenarios.
- The initiating events data was based on Westinghouse WCAP-15210 (Reference 10) to develop a generic prior and then Bayesian updated using Beaver Valley Unit 2 actual plant experience.
- The Electric Power Recovery model, updated with the latest system models, credited more scenarios with recovery of the fast bus transfer breakers, emergency diesel generators, and offsite grid.
- The turbine driven auxiliary feedwater pump failure data was revisited to see if any previously counted failures could be eliminated from inclusion into the plant specific data update. Of the eight failures included in the previous PRA model for the ZTPTSR (Turbine driven auxiliary feedwater pump failure to run during operation) failure rate, four failures to

run were eliminated and one failure to run was reclassified as a failure to start. Of the four failures to run that were eliminated; one was a packing leak, one was an oil leak, one that required OST support was moved into another failure, and one had instructions revised so that the governor valve linkage is no longer painted. This reduced the ZTPTSR failure rate by nearly 56%.

- The reactor trip breaker failure rates were now based on NUREG/CR-5500 (Reference 22) and then Bayesian updated using a more detailed analysis of Beaver Valley Unit 2 actual plant experience.
- Motor operated valve failure rates were based on NUREG-1715 (Reference 23) to develop a generic prior and then Bayesian updated using Beaver Valley Unit 2 actual plant experience.
- The SSPS split fractions were based on a CAFTA model using BVPS-2 plant specific components and Westinghouse generic failure rates. This model was developed as part of the risk-informed application for the Unit 2 Slave Relay Surveillance Test Interval Extension.
- Each of the emergency diesel generators were assigned 2.5% of unavailability associated with them based on the current INPO/WANO industry guidelines, which was intended to provide more hours for future on-line maintenance.

<u>Beaver Valley Unit 2 Revision 3B</u>

Beaver Valley Unit 2 Revision 3B was made with the following model modifications and incorporated the PRA Peer Review resolutions to the category A and B F&Os. The changes resulted in an internal events core damage frequency of <u>2.00E-05 / year</u>.

- The revised RCP Seal LOCA frequency also included plant specific thermal-hydraulic analyses performed with Modular Accident Analysis Program (MAAP) 4.0.4, which accounted for sequences that do not go to core melt during a 48-hour period, given that AFW is available, as non-core damage sequences. These analyses were performed for both Station Blackout and loss of all service water scenarios. RCP Seal LOCA sequences that uncover the core before 48 hours, but after 30 hours, used an electric power recovery factor based on the probability of not recovering offsite power before core damage occurs using the Plant-Centered LOSP Recovery lognormal distribution reported in NUREG/CR-5496 and the median probability of not recovering at least one emergency diesel generator at times greater than 24-hours (if available for recovery).
- The initiating events data was based on WCAP-15210 to develop a generic prior and then Bayesian updated using Beaver Valley Unit 2 actual plant experience. Based on the PRA Peer Review comments, the first year of commercial operation was excluded from the Bayesian update data. Additionally, LOCA initiating event frequencies were based on the interim LOCA frequencies taken from Table 4.1 of the "Technical Work to Support Possible Rulemaking for a Risk-Informed Alternative to 10CFR50.46/GDC 35", to account for aging-related failure mechanisms.
- In response to PRA Peer Review comments on the ATWS model, operator credit to perform emergency boration was now given even if earlier actions to manually trip the reactor or insert control rods fail.
- Based on the PRA Peer Review comments, the success terms for the component failure data were revisited and checked against the Maintenance Rule estimated demands and operating time given by the System Engineers, for a 13.2 year period. Any discrepancies between that used in the BV2REV3A data were resolved and the failure data was revised using a Bayesian update process in the BV2REV3B PRA model.

- The concerns of the PRA Peer Review on the interfacing system LOCA initiating event frequency were addressed using the latest industry information from NUREG/CR-5102 and NUREG/CR-5603. Additionally, the Monte Carlo value from this revised model was used for the initiating event frequency.

Beaver Valley Unit 2 Revision 4

Beaver Valley Unit 2 Revision 4 was made with the following model modifications. The changes resulted in an internal events core damage frequency of 9.53E-06 /year.

- The emergency diesel generator unavailability was once again based on historical BVPS unavailability, since extended on-line maintenance beyond 72-hours would require the availability of an additional AC power source (e.g., spare diesel generator) capable of supplying safe shutdown loads during a station blackout, per Amendments 1A-268 & 2A-150. Therefore, it is believed that there is a low probability that the extended AOT would ever be implemented, and hence, significant emergency diesel generator unavailability should only be accrued during plant outages.
- Credit was given for the Operators to align a spare battery charger on the 125V DC Busses 2-1 and 2-2 given that their primary battery charger has failed and the batteries are supplying the bus. These actions are now directed in Alarm Response Procedures 2OM-39.4.AAD and 2OM-39.4.AAE.
- Credit was given for the main feedwater pump discharge check valves (2FWS-1 & 2FWS-2) to prevent flow diversion from the auxiliary feedwater pumps, in conjunction with the previously modeled main feedwater check valves (2FWS-28, 29, & 30).
- The alternate high head safety injection flow path through 2SIS-MOV836 was credited, given the failure of the primary high head safety injection flow path through the 2SIS-MOV867 valves.
- The third train of station instrument air, consisting of an auto start, diesel driven station air compressor was included in the PRA model. This system also provides an air supply to the containment instrument air system.
- Credit for Operators to manually initiate safety injection following a large break LOCA was given, with an associated human error probability of 2.1E-02, as opposed to an assumed guaranteed failure in previous PRA models.
- The methodology used to calculate the human error probabilities was changed from the SLIM to the EPRI HRA Calculator. These new HEPs also used operator action timings based on plant specific MAAP thermal hydraulic analysis that included the EPU and ACC.
- The updated model used the latest NRC accepted methodology for determining RCP Seal LOCAs. This methodology is based on Westinghouse's WCAP-15603, Revision 1-A, "WOG 2000 Reactor Coolant Pump Seal Leakage Model for Westinghouse PWRs." The use of this revision differs from the previous PRA model in that the 57 gpm RCP seal LOCA probability was reassigned to the 182 gpm seal LOCA, and now has a zero probability. This is due to the NRC review of the WCAP, which concluded that given the failure of the second stage seal the third stage seal failure

probability is unity, since it is not designed to handle more than the normal operating pressure differential of a few psid. However, with this new RCP Seal LOCA model there is now a 79% probability that the seal leakage will not exceed 21 gpm per RCP during the loss of all seal cooling condition, which accounts for the installed high-temperature o-rings on all three RCPs.

- The revised RCP Seal LOCA frequency also included plant specific thermal hydraulic analyses performed with MAAP DBA and accounts for full EPU conditions. RCP Seal LOCA sequences that do not go to core melt during a 48 hour period, given that AFW is available, are not counted as core damage sequences, since it is believed that alternate equipment could be provided within this time frame to maintain the reactor in a safe stable state. These MAAP analyses were performed for both Station Blackout and loss of all river (service) water scenarios.
- The initiating events data was based on Westinghouse WCAP-15210, Revision 1, "Transient Initiated Event Operating History Database for U.S. Westinghouse NSSS Plants (1987 – 1997)" to develop a generic prior and then Bayesian updated using Beaver Valley Unit 2 actual plant experience from January 1, 1989 though December 31, 2005.
- The loss of offsite power (LOSP) initiating event was broken down into five separate initiators; (1) plant-centered, (2) grid-centered, (3) switchyard centered, (4) severe weather related, and (5) extreme weather related. The basis for these initiating event frequencies comes from NUREG/CR-INEEL/EXT-04-02326, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1986 – 2003 (Draft)," that were Bayesian updated with BVPS-2 plant specific data.
- The offsite power restoration probability curves used in the electric power recovery analyses were also based on NUREG/CR-INEEL/EXT-04-02326 potential bus restoration data using a composite curve. The composite curve is a frequency-weighted average of the four individual LOSP category curves (it excluded the extreme weather related data), which was Bayesian updated with plant-specific LOSP frequencies. The electric power recovery factors were not credited for extreme weather related LOSP initiators.
- The consequential loss of offsite power probability following reactor trips was updated.

3.1.2 External Events

For external events, the development of a list of possible scenarios is similar to that for internal events. Because of this, the models for external events can take advantage of much of the work completed for internal events. Rather than develop new event trees for external events, use is made of the most appropriate event trees developed earlier for internal events. Only the changes needed to account for the unique aspects of the external events are required.

3.1.2.1 Internal Fires

The fire analysis employs a scenario-based approach that meets the intent of NUREG-1407 to systematically identify fire and smoke hazards and their associated risk impact to BVPS-2. The analysis was divided into two phases: (1) a spatial interactions analysis phase and (2) a detailed analysis phase. In the spatial interactions analysis phase, one or more fire and smoke hazard scenarios were developed for each plant location that can potentially initiate a plant transient or affect the ability of the plant to mitigate an accident. The scenarios developed in this phase are called location scenarios. Conservative assumptions were made in the assessment of scenario impacts to screen out location scenarios that have a relatively insignificant impact on plant safety.

In the detailed analysis phase, detailed scenarios were developed for the location scenarios that survived the spatial interactions analysis screening. One or several frequency reduction factors (geometry factor, severity factor, fire nonsuppression factor, and nonrecovery factor) were assessed for each detailed scenario. As each frequency reduction factor was assessed, conservatism introduced in the earlier phase was reduced and the complexity of the analysis progressively increased. Whenever one or more reduction factors led to the conclusion that the risk associated with a detailed scenario was relatively insignificant, the analysis for that detailed scenario would be halted. Each detailed scenario was evaluated iteratively until the scenario was considered to be relatively risk insignificant or all frequency reduction factors were assessed. The plant vulnerabilities to fire and smoke hazards were assessed by aggregating the risk impact of the subscenarios. The frequency of fire and smoke hazard-initiated core damage sequences was used as a measure of the potential for plant vulnerabilities.

The containment performance in response to fire threats, Fire Risk Scoping Study (FRSS) issues, and other special safety issues were also evaluated. Low-cost risk management options could then be identified to reduce the risk impact associated with these scenarios.

The major steps of the Beaver Valley Fire Individual Plant Examination for External Events (IPEEE) are summarized as follows:

- Phase 1: Spatial Interactions Analysis

    1. Information Gathering and Data Collection
    2. Preliminary Screening and Identification of Important Locations
    3. Development of Location Scenarios
    4. Quantitative Screening

- Phase 2: Detailed Analysis

    5. Development and Analysis of Detailed Scenarios
    6. Sensitivity/Uncertainty Analysis
    7. Containment Performance Evaluation
    8. Resolution of the FRSS and Other Safety Issues

The BVPS-2 Fire PRA has not been explicitly updated since the IPEEE. However, as the Fire sequences are dependent on internal events modeling, the Fire sequences have implicitly been partially updated with updates to the internal events models. Additionally, screened-out detailed scenarios that were considered to be relatively risk insignificant in the IPEEE, but close to the threshold (1.4E-07/yr at Unit 2), were reanalyzed and included in subsequent PRA model revisions. Results of the Fire PRA for BVPS-2 are provided in the following Table 3.1.2.1-1

Table 3.1.2.1-1: Fire PRA Results	
	BVPS-2 PRA Model
Current Fire CDF (/year)	4.80E-06
IPEEE Fire CDF (/year)	1.05E-05

Beaver Valley Unit 2 IPEEE Information

The IPEEE concluded that there are no readily apparent vulnerabilities to fire events at BVPS-2. The discussion that follows highlights the most significant contributors, in terms of how the plant might be changed to reduce the already acceptable risk.

Two general areas for improvement are considered; i.e., the equipment impacts that may result from fires in key areas, and the plant response to the most risk significant postulated fires. The current controls in place at BVPS-2 are judged to be adequate to limit the frequency of fires from internal plant sources.

The extent of equipment impacted by a fire depends on the originating location and to a large extent, the amount and arrangement of cables within the rooms affected. For many of the key fire subscenarios identified, the equipment impacts are limited. For example, both trains of service water may be disabled by the fire, but there may be no other plant impacts. For such scenarios, repositioning of equipment or the rerouting of selected cables may be effective at reducing the risks of core damage.

Possible changes that might affect the frequency of the top five fire subscenarios that account for almost 53% of the fire-initiated CDF are discussed below and are presented in Table 3.1.2.1-2 (extracted from Table 7-1 of the BVPS-2 IPEEE) for BVPS-2. The frequency assessment of the key scenarios is consistent with the analysis in Appendix R, in that, for the key scenarios, it accounts for operator recovery actions that may have been credited in the Appendix R analysis.

Table 3.1.2.1-2: BVPS-2 IPEEE Model/Design Enhancements

CDF Key Contributor	Model or Design Enhancement	IPEEE CDF Importance: Percent of CDF	IPEEE CDF Importance: Risk Reduction Worth *	Percent of Total CDF **	Status
Emergency AC Power	Reevaluate diesel generator building fragility.	58.3 (Seismic)	0.7110 (Seismic)	4.1	The diesel generator building HCLPF is 0.28g, more than twice the SSE level. This along with a low contribution to total CDF warrants no further action.
CB-3 Fire	Provide operator credit for recovery of auxiliary feedwater from outside of control room.	17.8 (Fire)	0.79062 (Fire)	2.5	The low contribution to total CDF warrents no further action. This evaluation is consistent with the BVPS-1 analysis. However, the operator recovery credit could change if deemed necessary.
CT-1 Fire	Install qualified fire barriers between fire areas CB-1, CB-2 and CT-1.	12.6 (Fire)	0.9941 (Fire)	1.8	The low contribution to total CDF warrents no further action.
SB-4 Fire	Install an automatic CO2 fire supression system.	10.5 (Fire)	0.9380 (Fire)	1.4	The low contribution to total CDF warrents no further action.
CV-1 Fire	Reroute purple train service water pump/MOV power and control cables.	6.2 (Fire)	0.9941 (Fire)	0.9	The low contribution to total CDF warrents no further action.
CV-3 Fire	Reroute orange train CCP/thermal barrier cooling MOV and service water power and control cables.	5.8 (Fire)	0.9986 (Fire)	0.8	The low contribution to total CDF warrents no further action.

Notes: * The Risk Reduction Worth is the factor decrease in CDF that would be realized if the failure probability of the affected contributor was decreased to 0.0 (i.e., guaranteed success). ** Total CDF includes both internal and external events.

3.1.2.2 Seismic Events

A PRA was performed for internal initiating events on the Beaver Valley Power Station in satisfaction of the IPE requirements. To assess the risk contribution and significance of seismic-initiated events to the total plant risk, it was determined that the PRA method should also be used for the seismic analysis to meet the requirements of the IPEEE.

Beaver Valley selected the Seismic PRA option over the seismic margins option for the following reasons:

- With the existing PRAs for internal events that were developed to support the IPE and the decision to extend the PRA for all of the external events within the IPEEE scope, all severe accident issues are addressed within the context of an integrated PRA model that consistently treats all internal and external initiating events. This model rigorously accounts for all accident sequences resulting from any combination of internal and external events. The resulting risk information provided from this integrated approach was viewed as more useful to DLC management to make decisions about allocating resources to manage the risks of severe accidents.

- With the ability to link the Level 1 and Level 2 event trees as demonstrated in the IPE, the selected PRA approach was found to provide a more rigorous examination of potential containment vulnerabilities and seismic/systems interactions impacting containment effectiveness than was possible using the seismic margins approach.

The methodology selected is consistent with PRAs performed with the procedures contained in NUREG/CR-2300. In general, the methodology used in the analysis consisted of the following main steps:

- Seismic Hazard Analysis. Determination of the frequency of various potential peak ground accelerations (PGA) at the site, and an assessment of the likelihood of landslides and soil liquefaction.

- Fragility Analysis. Determination of the conditional failure probability of risk-related plant structures and components at peak ground accelerations.

- Plant Logic Analysis. Development of logic models that evaluate the potential structure and component failure scenarios. The models include seismic-induced failures that may initiate an accident scenario and may directly disable components or systems needed to successfully terminate the scenario. The models also include potential failures and unavailabilities of components due to nonseismic causes.

- Level 1/2 Integration. The linking of Level 1 seismic event trees with the Level 2 containment event tree for an integrated Level 2 PRA of seismic events and seismic/system integrations to examine containment effectiveness.

- Assembly and Quantification. Assembly of the seismic hazard, component fragilities and nonseismic unavailabilities, and plant logic models, including model quantification to obtain point estimates for core damage, plant damage state, release category, and scenario frequencies that result from seismic-initiated events.

- Uncertainty Quantification. Calculation of probability distributions for category (Level 2 results) and core damage frequencies (Level 1 results) that can be combined with the results from other initiating events.

The BVPS-2 Seismic PRA has not been explicitly updated since the IPEEE. However, as the seismic sequences are dependent on internal events modeling, the seismic sequences have implicitly been partially updated with updates to the internal events models. Additionally, BVPS-2 Revision 3A PRA model revised the component seismic fragilities based on the September 10, 1999 response to the Nuclear Regulatory Commission's IPEEE Request for Additional Information, dated July 8, 1999. This response noted that following a review of the analysis, the BVPS median capacities for those structures and equipment for which the seismic fragilities were directly calculated were overestimated by approximately 36%. Incorporating these new component fragilities resulted in the modeling of additional Seismic Top Events, as well as, increasing the failure probabilities. Results of the Seismic PRA for BVPS-2 are provided in the following Table 3.1.2.2-1

Table 3.1.2.2-1: Seismic PRA Results

	BVPS-2 PRA Model
Current Seismic CDF (/year)	9.70E-06
IPEEE Seismic CDF (/year)	5.33E-06 (Original) 1.03E-05 (RAI Revised)

Beaver Valley Unit 2 IPEEE Seismic Information

The IPEEE concluded that there are no readily apparent vulnerabilities to seismic events at BVPS-2. The discussion that follows highlights the most significant seismic contributors, in terms of what might be changed to reduce the already acceptable risk. Two general areas for improvement were considered; (1) the plant response to seismic-initiated failures, and (2) the equipment seismic fragilities.

For all but 2 of the top 50 highest frequency core damage sequences in the original IPEEE submittal, the conditional probability of core damage given the seismic initiating event and failures directly attributable to it are all 1.0. In the large majority of these sequences, either the seismic failures result in a station blackout, or the loss of all service water. In some of the top sequences, there may be two or more failures, which if they occurred alone, would each result in core damage. In the 2 sequences, which are an exception to the above, the seismic failure of the normal 4KV AC and 125V DC busses places a demand on the emergency diesel generators. The non-seismic, probabilistic failures of the diesel generators then result in a station blackout, given that the Unit AC power crosstie is unavailable due to the seismic failure of the normal 4KV busses. The CDF contribution from these 2 sequences is about 4.41E-08. Moreover, the total CDF from all similar sequences is only 1.75E-07. Therefore, it is concluded that options to improve the plant response to seismic events would not be effective in limiting risk. This conclusion was also reached in the IPEEE RAI response.

The offsite power grid, the 125V DC ERF Substation batteries, and the station air compressors/turbine building block walls are assessed as having the lowest fragility curves of those modeled. However, the most risk significant seismic fragility is that of the 4KV emergency bus transformers and diesel generators/DG building. Failures of these SSCs are assumed to result in the loss of emergency AC power and result in a station blackout leading to eventual core damage. Although enhancements to these SSCs could reduce the seismic CDF by almost 29%, they are not considered feasible since their HCLPF values exceed 0.28g (or more than twice the BVPS-2 SSE value of 0.125g) and the seismic CDF contribution is already low when compared to the internal events CDF.

These recommended enhancements to BVPS-2 are summarized in Table 3.1.2-1 (extracted from Table 7-1 of the BVPS-2 IPEEE).

Beaver Valley Unit 2 USI A-45 Resolution

Resolution of the external events portion of Unresolved Safety Issue A-45 was subsumed into the IPEEE requirements that allow plant-specific evaluation of the safety adequacy of decay heat removal systems.

The Beaver Valley Unit 2 PRA results do provide indications of the importance of systems that directly perform the decay heat removal function. The IPEEE indicated the importance of systems that perform the decay heat removal function. Five classes of systems were considered: main feedwater, auxiliary feedwater, bleed and feed cooling, steam generator depressurization for RCS cooldown, and closed loop residual heat removal. Importance was measured by the percentage of core damage frequency attributable to sequences that involve failure of the indicated split fraction. The importance measures are not additive because more than one of the ranked split fractions may, and often do, fail in the same sequence.

Two event tree top events are used to represent the main feedwater system. Top Event "MF" represents the hardware failure modes under normal operations and Top Event "OF" represents the operator action to realign main feedwater after a plant trip, given that auxiliary feedwater fails. All of the main feedwater system hardware failures occur in sequences in which main feedwater is lost due to the seismically caused loss of its support systems, i.e., split fraction MFF. Failure of the operators to realign main feedwater after the plant trip is dominated by earthquakes with PGAs above 0.5g.

Top Event "AF" represents the auxiliary feedwater system. The most important auxiliary feedwater system failures are due to operators failing to provide makeup water to the auxiliary feedwater pumps after the depletion of supply tank 2FWE-TK210 for earthquakes with PGAs above 0.5g. The next most important auxiliary feedwater system failures are failures of the turbine driven pump given loss of electrical support to the motor driven pumps.

Feed and bleed cooling is modeled by three separate event tree top events: Top Event "HH" for the HHSI pumps and flow path from the RWST, Top Event "HC" for the cold leg injection flow path, and Top Event "OB" that models the bleed path via the pressurizer. Because of the credit taken for realigning the electric-driven main feedwater pumps, the Beaver Valley Unit 2 design minimizes the frequency of sequences involving failure of AFW and bleed and feed cooling, relative to other PWRs. Two of these three top events ("HC" and "HH") are also used to model high head safety injection in the event of a small LOCA.

Top Event "CD" models the action to depressurize the steam generators in sequences where it is desirable to cool down and depressurize the RCS. Steam generator depressurization helps to limit RCS leakage during a station blackout or a steam generator tube rupture with a stuck-open secondary side valve. It is also used during small LOCAs in order to inject water into the reactor core with the low head safety injection pumps given the failure of the high head safety injection pumps. As can be seen from the percentage of contribution listed in IPEEE Table 3-18, such failures are relatively unimportant to the core damage frequency.

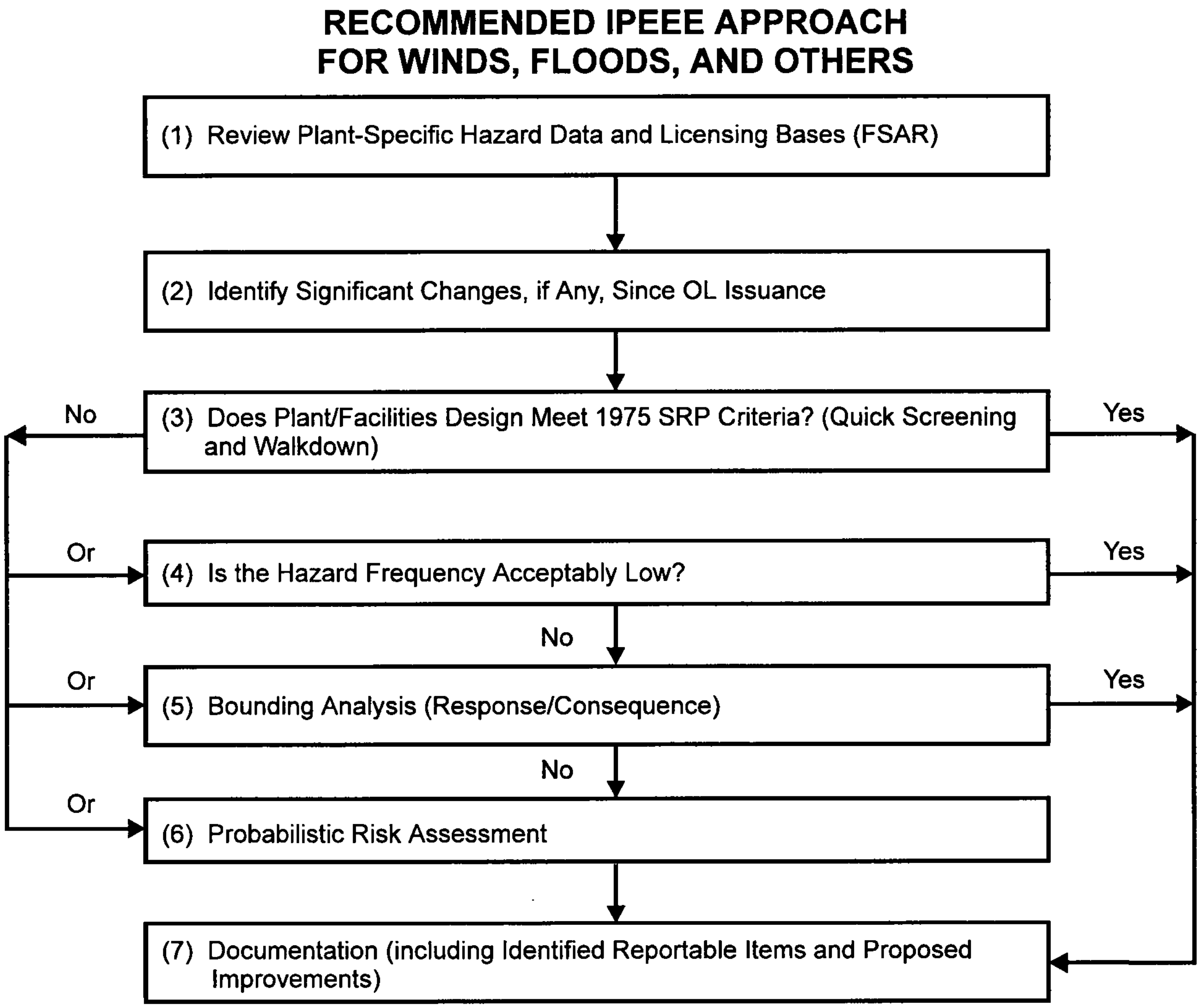
Finally, the importance of cooling via the residual heat removal system is also indicated in IPEEE Table 3-18. The RHR system plays only a minor role in the determination of the core melt frequency. By design, this system is tripped off on a Phase B containment isolation signal. No sequences greater than 1.6E-09 per year involved failure of the RHR.

In summary, no particular vulnerabilities of the Beaver Valley Unit 2 systems that are used to perform decay heat removal were identified. The majority of the seismic core damage frequency at Beaver Valley Unit 2 comes from the loss of emergency AC power caused by the seismic initiating event or failure of operator actions following earthquakes with PGAs above 0.5g. No discernible frequency comes from failures of decay heat removal.

3.1.2.3 Other External Events

NUREG-1407 recommends a screening type approach, as shown in Figure 3.1.2.3-1 (taken from Figure 5-1 of NUREG-1407), to evaluate the external hazards included in this section. The general methodology used at BVPS-2 follows the approach recommended by NUREG-1407 and consists of the following steps:

- Establishing a List of Plant-Specific Other External Events
- Progressive Screening
- Walkdown
- Documentation



Note: Steps 4 through 6 are optional.

Figure 3.1.2.3-1: NUREG-1407 Screening Approach

Based on the results in the BVPS-2 IPEEE, it was concluded that the plant structures at the site are well designed to withstand the high wind associated hazards and that no potential vulnerability is identified.

Since the plant and facilities design meets the 1975 SRP criteria, and that there are no existing plant changes that could affect the plant hazard data or the licensing bases with respect to flooding, the core damage frequency due to external flooding was estimated to be less than 1.0E-06 per year for BVPS-2.

The NRC staff concluded, in the BVPS-2 IPEEE SER, that, according to GDC 4, GDC 19, and SRP Section 2.2.3, the BVPS plant is adequately protected and acceptable with respect to transportation and nearby facility hazards.

Based on the review of the lightning events that have occurred at the site, it was concluded that they were less severe than a complete loss of offsite power to BVPS-2. Also, according to Section 2.6 of NUREG-1407, the probability of a severe accident caused by lightning would be relatively low. Therefore, lightning is an insignificant contributor to core damage frequency for BVPS-2.

The contribution to the BVPS-2 total CDF from the other external events is less than 1.0E-06 per year, and as concluded in the BVPS-2 IPEEE, there are no vulnerabilities to the other external events at BVPS-2.

3.1.2.4 External Event Severe Accident Risk

External event severe accident risk assessment is integrated with the internal events risk; the PRA includes both internal and external. This assessment approach provides the means to evaluate SAMAs for both internal and external events impacts simultaneously without the need to separately estimate the impact of the potential improvements on external events.

3.2 LEVEL 2 PLANT SPECIFIC MODEL

The Level 2 PRA model determines release frequency, severity, and timing based on the Level 1 PRA, containment performance, and accident progression analyses.

3.2.1 Description of Level 2 PRA Model

The accident sequence analysis defines the manner in which expected plant response to each identified initiating event or initiating event category is represented and quantified. This accounts for successes and failures of safety functions and related systems, and human actions to determine whether or not core damage occurs. The result of the Level 1 accident sequence analysis is the definition of a set of event trees used to represent and quantify the accident sequences.

The Level 2 analysis extends the Level 1 analysis to investigate the release category potential for core damage end states found. A containment event tree is used to represent and quantify the LERF potential when quantified with the Level 1 event trees.

The Level 2 analysis is highly interdependent with other PRA tasks. The accident sequence plant damage states define the categories of core damage sequences to be considered in the Level 2 analysis. The event tree used to represent and quantify the LERF potential is linked to the event trees representing the Level 1 analysis.

Each end state of the plant model (front-end or Level 1) event trees defines an accident sequence that results from an initiating event followed by the success or failure of various plant systems and/or the success or failure of operators to respond to procedures or otherwise intervene to mitigate the accident. Each accident sequence has a unique signature due to the particular combination of top event successes and failures. Each accident sequence that results in core damage could be evaluated explicitly in terms of the accident progression and the release of radioactive materials, if any, into the environment. However, since there can be millions of such sequences, it is impractical to perform thermal-hydraulic analyses and CET split-fraction quantification for each accident sequence. Therefore, for practical reasons, the Level 1 sequences are usually grouped into PDS (or accident class) bins, each of which collects all of those sequences for which the progression of core damage, the release of fission products from the fuel, the status of the containment and its systems, and the potential for mitigating source terms are similar. A detailed split-fraction analysis is then focused on specific sequences selected to represent risk-significant bins.

PDS bins have been used as the entry states (similar to initiating events for the plant model event trees) to the CETs. The PDS bins are characterized by thermodynamic conditions in the RCS and the containment at the onset of core damage, and the availability or unavailability of both passive and active plant features that can terminate the accident or mitigate the release of radioactive materials into the environment.

However, this was not the case in the BVPS-2 PRA models, where the CET was linked directly to the Level 1 trees to generate the frequencies of the defined release categories. Although the CET was linked directly to the Level 1 trees, the concept of PDSs was retained to minimize the number of CET top event split fractions that must be calculated. Furthermore, the CET was quantified separately for a number of key PDSs to facilitate debugging of the rules used for assigning CET split fractions and binning sequences to appropriate release categories.

The PDSs are characterized in such a manner to facilitate Level 2 quantification. However, the core damage frequency need not be characterized using the same PDS bins. In fact, Level 1 results have been characterized using much broader bin definitions.

Representative accident sequences must be selected to quantify split-fraction values for the CET. If PDSs are defined, a representative accident sequence(s) is selected for each risk-significant

PDS. These representative sequences are analyzed in detail with appropriate thermal-hydraulic and fission product transport codes such as the Modular Accident Analysis Program, the Source Term Code Package, and/or the MELCOR program to characterize the timing of important events (such as the onset of severe core damage and reactor vessel melt-through) as well as the nature of the core damage, containment failure, and fission product release.

The BV2REV4 PDS groups are presented in Table 3.2.1-4.

PDS groups are evaluated in a Containment Event Tree. CET sequences are then grouped and binned in previously defined release category bins based on sequence and containment conditions as shown in Table 3.2.1-5 (Table 4.7-7 in the BVPS-2 IPE Summary Report submittal).

The IPE source term evaluation was based on radionuclide releases of 20 Beaver Valley release category bins plus an intact containment bin. However, in support of the SAMA, BVPS has elected to upgrade the source release fractions for select bounding release categories based on current plant specific MAAP-DBA analyses that account for EPU conditions. In support of SAMA evaluations it is not necessary to run a MAAP case to represent each individual IPE release class for BVPS (i.e., BV1 – BV21). The release categories identified in Table 3.2.1-6 are those that are applicable to the plant's Level 3 and SAMA evaluations and were re-evaluated using MAAP-DBA. The specific MAAP cases provided in the table were judged to be sufficient to represent each release category identified in the BVPS SAMA evaluation.

All MAAP-DBA cases were analyzed for 24 hours after the time of release, or demonstrated that a complete release has been produced (i.e., at least 98% of the noble gases have been released from containment).

The Level 2 quantification extends the Level 1 results of the Beaver Valley Unit 2 PRA to include the Level 2 results. This extension has been accomplished by linking the CET (discussed earlier in this section) to the Level 1 trees, and by assigning the end states of the linked Levels 1 and 2 trees to the appropriate release categories. For reporting, the release categories have been binned into four groups, as shown in Table 3.2.1-1. Basic Event Importances (Table 3.2.1-2) and Component Importances (Table 3.2.1-3) for the Large Early Release category group are provided for information.

Table 3.2.1-1: BV2REV4 Release Category Group Definition and Results			
Release Type	**Description**	**Associated CDF (per year)**	**Percentage of Total CDF**
I	Large, early containment failures and bypasses	4.09E-07	1.7%
II	Small, early containment failures and bypasses	3.81E-06	15.9%
III	Late containment failures	1.86E-05	77.4%
IV	Long-term contained releases (intact containment)	1.20E-06	5.0%
Total Plant CDF		2.40E-05	100%

Table 3.2.1-2: BV2REV4 Basic Event Importances for Total Plant LERF by Risk Reduction Worth				
Rank	**Basic Event Name**	**Basic Event Description**	**RRW***	**Applicable SAMA**
1	OGXXXX	Offsite Grid Fails Following Non-LOSP Initiator	1.14E+00	AC Power SAMAs
2	OPRSL1	Operator Fails to Identify Ruptured Steam Generator or Initiate Isolation	1.14E+00	SAMA 178
3	OPROS1	Operator Fails to Initiate SI Following Steam Line Break	1.07E+00	SAMA 153
4	OPRSL3	Operator Fails to Gag Stuck Open SRV	1.07E+00	SAMA 164
5	[CBFC4KVS2A2A4 CBFC4KVS2D2D7]	CCF of SSST Incoming Circuit Breakers	1.04E+00	AC Power SAMAs
6	OPRSL2	Operator fails to locally close or isolate secondary relief valve	1.02E+00	SGTR SAMAs
7	OPRWM1	Operator Fails to Align Makeup to RWST - SGTR, Secondary Leak PR	1.02E+00	SAMA 169
8	EVFC2SVSHCV104	Residual Heat Release Valve 2SVS-HCV104 Fails to Close on Demand	1.02E+00	SGTR SAMAs
9	LHSI_PIPE_R	LHSI Pipe Rupture Given RCS Leak Rate to LPI Greater than 150 gpm	1.02E+00	LOCA SAMAs
10	SCENARIO1	Three cold Leg Check Valves Rupture	1.01E+00	SAMA ISLOCA

* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship:
$RRW = 1 / (1 - FV)$

Table 3.2.1-3: BV2REV4 Component Importances for Total Plant LERF by Risk Reduction Worth				
Rank	Component Name	Component Description	RRW	Applicable SAMA
1	2SVS-HCV104	Residual Heat Release Valve	1.02E+00	SGTR SAMAs
2	4KVS-2D-2D7	Incoming Supply Feed From TR-2B for Bus 2D (ACB-342B)	1.01E+00	AC Power SAMAs
3	2MSS-SV101C	(2RCS*SG21C) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
4	2MSS-SV102C	(2RCS*SG21C) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
5	2MSS-SV103C	(2RCS*SG21C) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
6	2MSS-SV101A	(2RCS*SG21A) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
7	2MSS-SV102A	(2RCS*SG21A) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
8	2MSS-SV103A	(2RCS*SG21A) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
9	2MSS-SV101B	(2RCS*SG21B) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
10	2MSS-SV102B	(2RCS*SG21B) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship: RRW = 1 / (1 - FV)				

Table 3.2.1-4
BV2REV4 Level 1 Sequence Groupings

RCS Pressure at Core Damage	Containment Bypassed		Containment Not Isolated	Containment Isolated	
	Small (SBYP)	Large (LBYP)		With Heat Removal (WCHR)	No Heat Removal (NOHR)
Low (L)) (0-200 psia)	LOSBYP	LOLBYP	LONISO	LOWCHR	LONOHR
Medium (MD) (200-600 psia)	MDSBYP	--	MDNISO	MDWCHR	MDNOHR
High (HI) (600-2,000 psia)	HISBYP	--	HINISO	HIWCHR	HINOHR
System Setpoint (SY) (>2,000 psia)	SYSBYP	--	SYNISO	SYWCHR	SYNOHR

Table 3.2.1-5 Beaver Valley Unit 2 PRA Release Categories

Release Category	RCS Pressure: High	RCS Pressure: Med	RCS Pressure: Low	Containment Failure: Intact	Containment Failure: Early	Containment Failure: Late	Containment Failure: Large	Containment Failure: Small	Containment Failure: Lrg Byp	Containment Failure: Sm Byp	Sprays?: Yes	Sprays?: Partial	Sprays?: No	Ex-Cont Retention*: None	Ex-Cont Retention*: Mod-erate	Ex-Cont Retention*: Signif-icant	Draft NUREG-1150 Dry PWR Cat	Major Release Type**
BV1	X				X		X						X	X			1, 6, 16	I
BV2	X				X		X				X—	—X		X			2, 7, 17	I
BV3		X	X		X		X						X	X			3, 5, 6, 18	I
BV4		X	X		X		X				X—	—X		X			4, 7, 19	I
BV5	X—	—X			X			X				X—	—X		X		6	
BV6	X—	—X			X			X			X				X		7	II
BV7			X		X			X				X—	—X		X		6	
BV8			X		X			X			X				X		7	
BV9	X—	—X				X	X						X	X			9	
BV10	X—	—X				X	X				X—	—X		X			8	
BV11			X			X	X						X	X			9	
BV12			X			X	X				X—	—X		X			8	
BV13	X—	—X				X		X				X—	—X		X		10	III
BV14	X—	—X				X		X			X				X		10	
BV15			X			X		X				X—	—X		X		10	
BV16			X			X		X			X				X		10	
BV17	X—	—X—	—X			X		X			X—	—X—	—X			X	13, 14	
BV18	X—	—X—	—X						X—	—X	X—	—X—	—X	X			12	I
BV19			X						X		X—	—X—	—X		X		11	
BV20	X—	—X								X	X—	—X—	—X			X	11	II
BV21	X—	—X—	—X	X							X			X			15-No Failure	IV

* "None" = direct or nearly direct to atmosphere (DF < 2), "Moderate" = through large building or with limited flooding (DF = 2 to 10), "Significant" = through deep pool or isolated steam generator (DF > 10)

** I = Large, Early Release, or Bypass, S/T equal to or greater than PWR4 (WASH-1400)

II = Small, Early Release, S/T less than PWR4 (WASH-1400)

III = Late Release, very low S/T

IV = Long-Term Containment Integrity, Minimal Release

X------X Indicates that the Release Category groups together two or more different characteristics

Table 3.2.1-6: BVPS Release Categories Reanalyzed Using MAAP-DBA			
Release Category	**IPE Release Category Description**	**Representative MAAP Accident Sequence**	**Assumed Containment Failure Area**
BV1	High RCS Pressure, Early, Large, No CHR.	SBO with no AFW and no sprays available. Large containment failure.	1 ft^2
BV3	Med/Low RCS Pressure, Early, Large, No CHR.	LLOCA with no active injection and no sprays. Large containment failure.	1 ft^2
BV5	High/Med RCS Pressure, Early, Small, Partial/No CHR, Yes Aux. Building.	SBO with no AFW and no sprays available. LOCI with a small release through the aux. building.	0.1 ft^2
BV7	Low RCS Pressure, Early, Small, Partial/No CHR, Yes Aux. Building.	LLOCA with no active injection and no sprays. LOCI with a small release through the aux. building.	0.1 ft^2
BV9	High/Med RCS Pressure, Late, Large, No CHR.	SBO with no AFW and no sprays available. Large containment failure due to over-pressurization.	1 ft^2
BV10	High/Med RCS Pressure, Late, Large, Partial CHR.	TLOFW with no active injection and partial sprays available. Large containment failure from H_2 burn.	1 ft^2
BV12	Low RCS Pressure, Late, Large, Partial CHR.	LLOCA with no active injection and partial sprays available. Large containment failure from H_2 burn.	1 ft^2
BV13	High/Med RCS Pressure, Late, Small, Partial/No CHR, Yes Aux. Building.	SBO with no AFW and no sprays available. Small containment failure due to over-pressurization.	0.2 ft^2
BV15	Low RCS Pressure, Late, Small, Partial/No CHR, Yes Aux. Building.	LLOCA with no active injection and no sprays available. Small containment failure due to over-pressurization.	0.2 ft^2
BV17	High/Med/Low RCS Pressure, Late, Small, Yes/Partial/No CHR, Ground.	SBO with no AFW and no sprays available. Failure through base of containment.	1 ft^2
BV18	High/Med/Low RCS Pressure, Large/Small Bypass, Yes/Partial/No CHR, Little or No Ex-Cont Retention.	SGTR with a TLOFW, no active injection and no sprays available. Direct release through stuck open MSSVs,	Containment Bypassed (DF=1.0)
BV19	Low RCS Pressure, Large Bypass, Yes/Partial/No CHR, Moderate Ex-Cont. Retention.	Large ISLOCA through low pressure injection system, no injection and no sprays available. Aux. building release below water level (flooded building provides scrubbing).	Containment Bypassed (DF=4.3)
BV20	High/Med RCS Pressure, Small Bypass, Yes/Partial/No CHR, Significant Ex-Cont. Retention.	Small ISLOCA through low pressure injection system, no injection and no sprays available. Aux. building release below water level (flooded building provides scrubbing).	Containment Bypassed (DF=10)
BV21	High RCS Pressure, Intact Containment, CHR available.	SLOCA with a TLOFW, no injection during recirculation and sprays available. No containment failure.	2.5E-05 ft^2 (Based on 0.1% volume / day leakage)

3.2.2 Level 2 PRA Model Changes Since IPE Submittal

The major Level 2 changes incorporated into each revision of the Beaver Valley Unit 2 PRA model are discussed below. The individual affect on risk by incorporating each of these changes has not been analyzed.

Beaver Valley Unit 2 Revision 0

This revision represents the base case IPE quantification and resulted in a large early release frequency of 8.44E-06 / year for internal events.

Beaver Valley Unit 2 Revision 1

This revision represents the base case IPEEE PRA model. There was only 1 major Level 2 change incorporated into this updated BVPS-2 PRA model. This change was implemented due to a reevaluation of the impact of direct containment heating (DCH) on the frequency of large, early releases at Beaver Valley Units 1 and 2.

The Direct Containment Heating issue was identified in the NRC's Revised Severe Accident Research Plan as an important issue for resolution because of its potential for early containment failures. DCH was recognized to be a potential by which sensible heat energy can be transferred directly to the reactor vessel and subsequent blowdown of the molten debris and RCS fluids into the containment atmosphere. If the RCS pressure is sufficiently high, the blowdown of the RCS fluid through an opening in the bottom head of the reactor vessel can entrain molten core debris in the high-velocity blowdown gas and eject fragmented particles from the reactor cavity into the containment. This series of events is referred to as high pressure melt ejection.

The Beaver Valley IPE submittals were based on an understanding of DCH phenomena as it was portrayed in the documentation (NUREG-1150 and NUREG/CR-4551) for the NRC's probabilistic assessment of severe accidents of five plants. Since that time, the state of knowledge regarding DCH phenomena evolved as additional experiments and analyses were performed. Two subsequent reports, NUREG/CR-6109 (Reference 17) and NUREG/CR-6338 (Reference 18) were issued by the NRC that relate to the resolution of DCH for Westinghouse plants with large, dry containments, including the Beaver Valley subatmospheric containments.

The conclusion of these reports is that the intermediate compartment traps most of the debris dispersed from the reactor cavity and that the thermal-chemical interactions during this dispersal process are limited by the incoherence in the steam blowdown and melt entrainment process.

Based on these new reports, the split fraction values for determining large, early containment failures (i.e., the product of C2 and L2) have reduction factors ranging from approximately 42 to more than 30,000 when compared to the IPE submittal.

This change to the Level 2 model contributed to a large early release frequency of 9.05E-07 / year for internal events.

Beaver Valley Unit 2 Revision 2

This revision simply integrated the Beaver Valley Unit 2 Revision 1, Level 1 and Level 2 PRA models into a single PRA model. The internal events large early release frequency remained at 9.05E-07 / year. There were no changes to the Level 2 PRA model.

Beaver Valley Unit 2 Revision 3A

Beaver Valley Unit 2 Revision 3A was made with the following model modifications. These changes contributed to a large early release frequency of 5.10E-07 / year for internal events.

There were four major Level 2 changes incorporated into the updated Beaver Valley Unit 1 PRA model. Three of the changes dealt with sequences involving induced SGTRs, large containment failures due to early hydrogen burns, and large containment failures due to alpha-mode (in-vessel steam explosions). Based on Westinghouse and industry state-of-the-art knowledge of these containment phenomenologies, it was then believed that the probabilities of these occurring was extremely low for large, dry containments (that is, non ice-condenser) and was not credible in large containment failures or bypasses.

The fourth change reclassified all early SGTR core damage sequences with wet SGs (i.e., auxiliary feedwater available) as small early releases without regard to break location or other sequence specific conditions such as SG isolation, primary to secondary pressure equalization, etc., based on significant fission product release scrubbing.

Beaver Valley Unit 2 Revision 3B

Beaver Valley Unit 2 Revision 3B was made with the following model modification. This change contributed to a large early release frequency of 1.14E-06/ year for internal events.

Based on the PRA Peer Review comments, the SGTR sequences were again reclassified so that only those that have a depleted RWST or have a loss of all secondary cooling were considered to be LERF contributors. It was assumed that leakage from the RCS would continue indefinitely through the faulted steam generator and the core will uncover after the RWST depletes. This is in agreement with WCAP-15955, "Steam Generator Tube Rupture PRA Notebook".

Beaver Valley Unit 2 Revision 4

There were no specific changes to the Beaver Valley Unit 2 Level 2 model in this revision. Changes to the Level 1 model resulted in a large early release frequency of 4.06E-07/ year for internal events.

Based on a review that was performed to identify the effects of the EPU and the contributors to the Large Early Release conditional probability, there were no Level 2 changes required due to the BVPS-2 containment conversion. The sub-atmospheric containment modeling in the previous BVPS-2 PRAs assumed no large pre-existing containment isolation failures, due to the inability to maintain a containment vacuum. This assumption remains valid for EPU and the slightly subatmospheric conditions now existing, as the containment vacuum pumps are not expected to maintain the slightly sub-atmospheric condition for large pre-existing containment isolation failures, as well.

However, there were two major contributors to the reduction in the Level 2 LERF incorporated into the updated BVPS-2 PRA model. These changes dealt with sequences involving steam generator tube ruptures with stuck-open safety valves. In the PRA model, only steam generator tube ruptures that are faulted and have a depleted RWST or have a loss of all secondary cooling are considered to be LERF contributors. For these sequences it is assumed that leakage from the RCS would continue indefinitely through the faulted steam generator and the core would uncover after the RWST depletes. These assumptions are in agreement with WCAP-15955, "Steam Generator Tube Rupture PRA Notebook" (Reference 19). Therefore, by lowering the probability of having a stuck-open steam generator safety valve on the ruptured steam generator, it would reduce the LERF. The Level 1 model changes that were implemented involve reducing the probability of having a stuck-open steam generator safety valve on the ruptured steam generator. These include making an assumption that only three of the five safety valves on a ruptured steam generator would lift in response to the pressure spike (based on simulator experience), and crediting operators to gag any safety valves that stick open with an associated human error probability of 2.1E-01.

3.3 MODEL REVIEW SUMMARY

Regulatory Guide (RG) 1.174 (Reference 38), Section 2.2.3 states that the quality of a PRA analysis used to support an application is measured in terms of its appropriateness with respect to scope, level of detail and technical acceptability, and that these are to be commensurate with the application for which it is intended.

The PRA technical acceptability of the model used in the development of this Severe Accident Mitigation Alternatives application has been demonstrated by a peer review process. The peer review was conducted in July 2002, by the [former] Westinghouse Owner's Group, with the final documentation of the review issued in December 2002. The overall conclusions of the peer review were:

> All of the technical elements were graded as sufficient to support applications requiring the capabilities defined for grade 2. The BVPS PRA thus provides an appropriate and sufficiently robust tool to support such activities as Maintenance Rule implementation, supported as necessary by deterministic insights and plant expert panel input.
>
> All of the elements were further graded as sufficient to support applications requiring the capabilities defined for grade 3, e.g., risk-informed applications supported by deterministic insights but in some cases this is contingent upon implementation of recommended enhancements.

After the peer review, the preliminary Category A and B facts and observations that potentially impacted the model were entered into the BVPS Corrective Action Program, dispositioned, and incorporated into updated PRA model. Although the facts and observations were written for the BVPS-2 model, if applicable, the resolution was applied to the BVPS-1 model as well. Those models have since undergone another revision, but the incorporated resolution of Category A and B facts and observations were maintained in the revision. The BVPS-2 Category A facts and observations (F&Os) and dispositions are summarized in the following paragraphs.

In addition, FENOC provided summaries of the BVPS Peer Review Category A and B F&Os in the following previously docketed letters:

- Pearce/USNRC, Beaver Valley Power Station, Unit No. 2, BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests No. 180, dated October 24, 2003, Serial L-03-160.
- Pearce/USNRC, Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66 and BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests Nos. 306 and 176, dated October 29, 2004, Serial L-04-141.

<u>**Category A Observations**</u>

F&O 1

Summary: This observation was identified in the Accident Sequence Analysis Sub-element regarding the RCP seal LOCA model. It was recognized that the BVPS RCP seal LOCA model used the WOG 2000 as a basis, but in a way that is more optimistic than most other Westinghouse plants. The BV2REV3A PRA model, RCP seal LOCA success criteria was developed from best estimate MAAP runs performed specifically for BVPS-2. Since certain MAAP results did not go to core uncovery in the assumed 24-hour mission time for the smaller break seal LOCA sizes, they were binned into the success (non CDF) end state, even though electric power or service water was not restored. The peer review team felt that additional MAAP analyses should be performed to investigate the impact of varying MAAP input parameters on the resultant time to core uncovery, and extend the run time to show stable plant conditions.

Resolution: Additional MAAP uncertainty cases for BVPS-2 were performed using pessimistically biased values along with setting input parameters to their high or low limits. These cases were run out to 48-hours or until core damage occurred. The success state for the BV2REV3B PRA model was redefined as any case (including uncertainties) that did not go to core damage before 48-hours. For cases that went to core damage before 48-hours but after 20-hours, additional electric power recovery values were used, based on NUREG/CR-5496. For cases that lead to core uncovery before 20-hours, a plant specific electric power recovery model was used. If electric power recovery was successful for these cases, the sequence was also binned to the success end state.

F&O 2

Summary: This observation was identified in the Thermal Hydraulic Analysis Sub-element regarding room heatup calculations. This observation found that the loss of ventilation room heatup analysis for the Safeguards Building, which houses Auxiliary Feedwater, Low Head Safety Injection, and Quench Spray pumps, used heat loads based on non-DBA conditions with only the AFW pump operating. This resulted in a room heatup that was well below the Equipment Qualification (EQ) temperature limits, and therefore, the ventilation dependency for these pumps was not modeled in the BV2REV3A PRA. The peer review team recommended that the room heatup calculation be re-evaluated using the appropriate DBA heat loads, and determine the impact on the effected components.

Resolution: A new room heatup analysis was performed for the Safeguards Building using realistic time-dependent DBA heat loads, based on MAAP generated success criteria. The results of this analysis were reviewed and compared to the EQ temperature limits to see if the necessary components to mitigate core damage or containment failures would be functional at the time that they were required to function (up to 24 hours). It was concluded that all PRA modeled equipment located within the Safeguards Building would be available to perform its PRA function during a loss of all ventilation for up to 24 hours. Therefore, it was determined that the Safeguards Building ventilation system is not required for support of the PRA modeled equipment located within the area, and the BV2REV3A PRA modeling assumptions regarding this remain valid. The BV2REV3B PRA model was not changed as a result of this observation.

F&O 3

Summary: This observation was identified in the Data Analysis, Failure Probability Sub-element. It was observed that the number of demands for several components seemed very high, and that the BVPS-2 plant specific Bayesian updating of independent failure data for these components resulted in more optimistic failure rates than most other Westinghouse plants. The peer review team recommended that the component demands be verified.

Resolution: As a resolution to this PRA Peer Review observation, the success data (demands and hours of operation) for all Unit 2 components that used Bayesian updating of their failure rates were checked against the Maintenance Rule estimated success data, and were revised as needed if discrepancies were found. Additionally, all RISKMAN failure data distributions that were Bayesian updated in the BV2REV3A PRA model were revised in the BV2REV3B PRA model using the results of review for estimated demands and hours of operation. All Top Events were requantified in the BV2REV3B PRA model using these revised component failure rates, which were then used to requantify the CDF and LERF.

F&O 4

Summary: This observation was identified in the Human Reliability Analysis (HRA), Post-Initiator Human Actions Sub-element. It was observed that the BVPS human error rates were developed using the Success Likelihood Index Methodology (SLIM) based on calibration curves from other plant HRAs from the mid-1980's. The peer review team recommended that these calibration curves be updated with current operator performance in the nuclear power industry.

Resolution: As a resolution to this PRA Peer Review observation all operator actions having a Risk Achievement Worth (RAW) greater than 2 (generally accepted as the risk significant threshold) were compared to similar actions for all Westinghouse plants by using the WOG/B&WOG PRA Comparison Database (Revisions 2 and 3). Additionally, a smaller subset of these plants was also looked at. These consisted of; Westinghouse 3-loop plants (since these were assumed to have similar operation action completion times based on plant power to heatup volume ratios), plants that also used the SLIM process, and Indian Point 2, which received a superior finding in their Human Reliability Analysis peer review. The results of this comparison show that the human error rates used in the BV2REV3A PRA model are all within the range of both comparison groups defined above, except for human action OPRCD3 (operator fails to cooldown and depressurize during a SGTR). However, the BV2REV3A value is of the same order of magnitude as most of the other plants reviewed and is not considered to be an outliner. It is therefore believed that the basic error curves used in the calibration of the BV2REV3A HRA are not grossly out of date, and that the current human error rates used in the PRA model are acceptable as is. Moreover, as a final resolution to this observation, future updates of the BVPS PRA models will use the EPRI HRA Calculator, which uses a more current and robust methodology. The BV2REV3B PRA model was not changed as a result of this observation.

F&O 5

Summary: This observation was identified in the Human-Reliability Analysis, Dependence Among Actions Sub-element. It was observed that the BVPS HRA did not have a documented process to perform a systematic search for dependent human actions credited on individual sequences and a method to adjust dependencies between multiple human error rates in the same sequence. The peer review team recommended that a robust technique be developed, documented, and used for the identification and quantification of dependent human error rates (HERs).

Resolution: In the initial development of the IPE HRA, an effort was made to eliminate the dependency between human actions by adjusting the split fraction value of the second dependent action, given that the first action failed. For example, if the operators failed to manually reestablish Main Feedwater following the failure of Auxiliary Feedwater, the human error rate for implementing Bleed and Feed cooling later in the accident progression was adjusted upwards. If the dependent actions were required to take place in the same period of time during the accident progression, the second dependent action was assigned to be a guaranteed failure. For example, if the operators failed to cooldown and depressurize the RCS by using the secondary coolant system, no credit was given to the operators to depressurize the RCS using the Pressurizer PORVs. However, as a resolution to this PRA Peer Review observation a method was established to verify that all dependent operator actions were captured by reviewing sequences with two or more failed split fractions that have a contribution from human actions. Of the sequences reviewed, the human actions were either previously adjusted during the IPE HRA, or were determined to be independent between split fractions. This independence was based on the actions not being conducted by the same set of operators (e.g., control room Reactor Operator action vs. local Auxiliary Plant Operator action), or different procedures being used separated by sufficient time in the accident progression (e.g., actions to makeup to the RWST given SI recirculation failures, following operator actions to align a spare Service Water pump earlier in the accident sequence progression). Human actions that are modeled in a single top event have appropriate dependencies modeled in the fault trees. Moreover, as a final resolution to this observation, future updates of the BVPS PRA models will use the EPRI HRA Calculator, which uses a more current and robust methodology. The BV2REV3B PRA model was not changed as a result of this observation.

3.4 LEVEL 3 PRA MODEL

The BVPS-1/2 Level 3 PRA model determines off-site dose and economic impacts of severe accidents based on the Level 1 PRA results, the Level 2 PRA results, atmospheric transport, mitigating actions, dose accumulation, early and latent health effects, and economic analyses.

The MELCOR Accident Consequence Code System (MACCS2) Version 1.13.1 was used to perform the calculations of the off-site consequences of a severe accident. This code is documented in NUREG/CR-6613 (Reference 28), "Code Manual for MACCS2: Volumes 1 and 2."

Plant-specific release data included the time-dependent nuclide distribution of releases and release frequencies. The behavior of the population during a release (evacuation parameters) was based on plant and site-specific set points. These data were used in combination with site-specific meteorology to simulate the probability distribution of impact risks (both exposures and economic effects) to the surrounding 50-mile radius population as a result of the release accident sequences at Beaver Valley.

The following sections describe input data for the MACCS2 (Reference 28) analysis tool. The analyses are found in References 32-35.

3.4.1 Population Distribution

The population surrounding the Beaver Valley Power Station site, up to a 50 mile radius, was estimated based on the most recent United States Census Bureau decennial census data. Details are provided in "Calculation Package for Population Projections – Beaver Valley Power Station" (Reference 29). The population distribution was estimated in 9 concentric bands at 0 to 1 mile, 1 to 2 miles, 2 to 5 miles, 5 to 10 miles, 10 to 15 miles, 15 to 20 miles, 20 to 30 miles, 30 to 40 miles, and 40 to 50 miles, and 16 directional sectors with each direction consisting of 22.5 degrees. The population was projected to the year 2047 by calculating an annual growth rate for each county in the 50 mile radius derived from state and national population projections. Geometric growth rates were calculated for each county in Ohio and Pennsylvania based on 2030 county projections. However, if the county population had decreased from 2000 to 2030, it was assumed there was no growth through 2030 (i.e., the 2030 population was equal to the 2000 population), and the national growth rate was applied from 2030 to 2047 to obtain an overall multiplier fore the 2047 projection. For West Virginia, projections were available through 2050. The annual growth rate was applied to obtain a 2047 multiplier, unless a negative growth rate existed, in which case no growth was assumed. The population distribution used in this analysis is provided in the following table.

Table 3.4.1-1 Population Projections Used in SAMA Analysis

From Radius	To Radius	Direction	Code	2000 Population	2047 Population
0	1	N	1	0	0
0	1	NNE	2	0	0
0	1	NE	3	93	110
0	1	ENE	4	38	45
0	1	E	5	88	104
0	1	ESE	6	0	0
0	1	SE	7	7	8
0	1	SSE	8	0	0
0	1	S	9	0	0
0	1	SSW	10	0	0
0	1	SW	11	2	2
0	1	WSW	12	0	0
0	1	W	13	0	0
0	1	WNW	14	0	0
0	1	NW	15	132	156
0	1	NNW	16	53	63
1	2	N	17	197	232
1	2	NNE	18	62	73
1	2	NE	19	4	5
1	2	ENE	20	7	8
1	2	E	21	74	87
1	2	ESE	22	64	76
1	2	SE	23	116	137
1	2	SSE	24	22	26
1	2	S	25	18	21
1	2	SSW	26	35	41
1	2	SW	27	25	30
1	2	WSW	28	73	86
1	2	W	29	141	166
1	2	WNW	30	0	0
1	2	NW	31	1,651	1,948
1	2	NNW	32	470	555
2	5	N	33	835	985
2	5	NNE	34	1,016	1,199
2	5	NE	35	1,130	1,333
2	5	ENE	36	683	806
2	5	E	37	1,039	1,226
2	5	ESE	38	713	841
2	5	SE	39	284	335
2	5	SSE	40	637	752
2	5	S	41	486	573
2	5	SSW	42	742	876
2	5	SW	43	619	730
2	5	WSW	44	217	256
2	5	W	45	723	853
2	5	WNW	46	802	946
2	5	NW	47	1,753	2,069
2	5	NNW	48	573	676

Table 3.4.1-1 Population Projections Used in SAMA Analysis (Cont.)

From Radius	To Radius	Direction	Code	2000 Population	2047 Population
5	10	N	49	2,317	2,734
5	10	NNE	50	3,875	4,573
5	10	NE	51	18,262	21,549
5	10	ENE	52	14,995	17,694
5	10	E	53	19,461	22,964
5	10	ESE	54	7,307	8,606
5	10	SE	55	1,589	1,840
5	10	SSE	56	1,777	2,090
5	10	S	57	4,734	5,586
5	10	SSW	58	1,284	1,512
5	10	SW	59	3,604	3,875
5	10	WSW	60	1,886	1,918
5	10	W	61	19,534	21,213
5	10	WNW	62	7,332	8,652
5	10	NW	63	2,156	2,544
5	10	NNW	64	1,283	1,514
10	15	N	65	4,297	5,070
10	15	NNE	66	20,102	23,720
10	15	NE	67	18,866	22,262
10	15	ENE	68	13,403	15,810
10	15	E	69	18,133	20,507
10	15	ESE	70	31,028	31,750
10	15	SE	71	5,136	5,187
10	15	SSE	72	1,105	1,132
10	15	S	73	1,064	1,099
10	15	SSW	74	5,120	5,285
10	15	SW	75	9,357	9,802
10	15	WSW	76	1,931	2,095
10	15	W	77	6,926	7,980
10	15	WNW	78	3,491	4,119
10	15	NW	79	2,716	3,205
10	15	NNW	80	1,975	2,331
15	20	N	81	2,679	3,161
15	20	NNE	82	19,651	23,188
15	20	NE	83	8,256	10,097
15	20	ENE	84	26,225	35,104
15	20	E	85	20,890	21,130
15	20	ESE	86	32,047	32,367
15	20	SE	87	20,102	20,303
15	20	SSE	88	5,210	5,342
15	20	S	89	5,479	5,643
15	20	SSW	90	23,299	23,522
15	20	SW	91	6,325	7,364
15	20	WSW	92	1,568	1,850
15	20	W	93	1,535	1,811
15	20	WNW	94	3,151	3,718
15	20	NW	95	5,793	6,836
15	20	NNW	96	9,801	11,565
20	30	N	97	40,448	47,729

Table 3.4.1-1 Population Projections Used in SAMA Analysis (Cont.)

From Radius	To Radius	Direction	Code	2000 Population	2047 Population
20	30	NNE	98	25,927	31,193
20	30	NE	99	11,544	15,668
20	30	ENE	100	26,859	36,797
20	30	E	101	73,055	77,064
20	30	ESE	102	410,196	414,298
20	30	SE	103	227,938	230,716
20	30	SSE	104	39,083	40,229
20	30	S	105	5,494	5,656
20	30	SSW	106	38,710	41,558
20	30	SW	107	20,523	24,217
20	30	WSW	108	5,090	6,155
20	30	W	109	4,182	5,480
20	30	WNW	110	10,727	12,776
20	30	NW	111	33,243	39,227
20	30	NNW	112	38,242	45,126
30	40	N	113	27,393	32,324
30	40	NNE	114	14,394	17,649
30	40	NE	115	20,468	28,041
30	40	ENE	116	52,734	72,065
30	40	E	117	88,641	97,229
30	40	ESE	118	343,130	347,829
30	40	SE	119	114,676	116,792
30	40	SSE	120	49,039	50,510
30	40	S	121	10,274	10,553
30	40	SSW	122	35,720	38,675
30	40	SW	123	10,554	12,454
30	40	WSW	124	6,314	8,164
30	40	W	125	15,333	21,441
30	40	WNW	126	25,741	30,543
30	40	NW	127	19,379	22,864
30	40	NNW	128	218,945	258,355
40	50	N	129	67,035	79,101
40	50	NNE	130	26,361	31,533
40	50	NE	131	9,705	13,035
40	50	ENE	132	31,197	37,772
40	50	E	133	43,404	48,911
40	50	ESE	134	115,071	120,818
40	50	SE	135	79,774	83,809
40	50	SSE	136	21,216	21,842
40	50	S	137	5,221	5,321
40	50	SSW	138	72,617	79,681
40	50	SW	139	12,337	14,558
40	50	WSW	140	9,276	11,210
40	50	W	141	19,628	24,920
40	50	WNW	142	83,296	97,999
40	50	NW	143	26,594	30,210
40	50	NNW	144	123,093	145,250
			Total	**3,273,502**	**3,607,001**

3.4.2 Economic Data

The Environmental Protection Agency's computer program SECPOP was the basis for the economic data used in the offsite evaluations done in this analysis. This code utilized county economic factors derived from the 2000 census and various other government sources dated 1997 to 1999. For the preparation of data for the Beaver Valley model, the county data file was updated to circa 2002 for the 23 counties within 50 miles of the plant. Reference 33 provides the input data used in this analysis:

Variable	Description	BV1/2 Value
DPRATE(1)	Property depreciation rate (per yr)	0.20
DSRATE(1)	Investment rate of return (per yr)	0.12
EVACST(2)	Daily cost for a person who has been evacuated ($/person-day)	$49
POPCST(2)	Population relocation cost ($/person)	$13,727
RELCST(2)	Daily cost for a person who is relocated ($/person-day)	$49
CDFRM(2)	Cost of farm decontamination for various levels of decontamination ($/hectare)	$1,169 & $2,598
CDNFRM(2)	Cost of non-farm decontamination per resident person for various levels of decontamination ($/person)	$6,236 & $16,630
DLBCST(2)	Average cost of decontamination labor ($/man-year)	$72,756
VALWF(2)	Value of farm wealth ($/hectare)	$6,957
VALWNF(2)	Value of non-farm wealth average in US ($/person)	$181,881

(1) DPRATE and DSRATE are based on MACCS2 Users Manual (Reference 28)

(2) Calc 17676-0002 "Beaver Valley Power Station - MACCS2 Input Data".

3.4.3 Nuclide Release

The equilibrium core inventory was assumed at the end of a fuel cycle with fuel from three different fuel cycles in equal proportions. It was originally developed using ORIGEN-S as described in the BVPS Containment Conversion Licensing Report (Reference 31).

The following table provides the inventory of the core at shutdown used in this analysis. This information is from Reference 30, Section 5.2.3.3

Table 3.4.3-1 Core Inventory

Nuclide	Core Inventory (Curies)
Ag-111	5.05E+6
Ag-112	2.28E+6
Am-241	1.17E+4
Am-242	7.04E+6
Am-244	1.89E+7
Ba-137m	9.35E+6
Ba-139	1.41E+8
Ba-140	1.42E+8
Br-82	3.02E+5
Br-83	9.37E+6
Ce-141	1.30E+8
Ce-143	1.21E+8
Ce-144	9.82E+7
Cm-242	2.42E+6
Cm-244	5.97E+5
Cs-134	1.57E+7
Cs-134m	3.69E+6
Cs-135m	4.39E+6
Cs-136	4.97E+6
Cs-137	9.81E+6
Cs-138	1.48E+8
Eu-156	2.29E+7
Eu-157	2.41E+6
H-3	4.36E+4
I-129	2.86E+0
I-130	2.07E+6
I-131	7.78E+7
I-132	1.14E+8
I-133	1.60E+8
I-134	1.77E+8
I-135	1.52E+8
Kr-83m	9.46E+6
Kr-85	8.27E+5
Kr-85m	1.95E+7
Kr-87	3.91E+7
Kr-88	5.43E+7
La-140	1.46E+8
La-141	1.29E+8
La-142	1.26E+8
La-143	1.20E+8

Table 3.4.3-1 Core Inventory (Cont.)

Nuclide	Core Inventory (Curies)
Mo-101	1.33E+8
Mo-99	1.45E+8
Nb-95	1.34E+8
Nb-95m	1.52E+6
Nb-97	1.27E+8
Nb-97m	1.19E+8
Nd-147	5.22E+7
Nd-149	3.02E+7
Nd-151	1.58E+7
Np-238	3.98E+7
Np-239	1.66E+9
Np-240	4.32E+6
Pd-109	3.26E+7
Pm-147	1.38E+7
Pm-148	1.41E+7
Pm-148m	2.37E+6
Pm-149	4.82E+7
Pm-151	1.60E+7
Pr-142	5.57E+6
Pr-143	1.18E+8
Pr-144	9.89E+7
Pr-144m	1.38E+6
Pr-147	5.18E+7
Pu-238	3.40E+5
Pu-239	2.86E+4
Pu-240	3.87E+4
Pu-241	1.13E+7
Pu-242	2.01E+2
Pu-243	4.23E+7
Rb-86	1.69E+5
Rb-88	5.57E+7
Rb-89	7.26E+7
Rh-103m	1.26E+8
Rh-105	8.16E+7
Rh-106	5.13E+7
Ru-103	1.26E+8
Ru-105	8.90E+7
Ru-106	4.63E+7
Sb-127	6.92E+6
Sb-129	2.52E+7

Table 3.4.3-1 Core Inventory (Cont.)

Nuclide	Core Inventory (Curies)
Sb-130	8.37E+6
Sb-131	6.09E+7
Se-83	4.42E+6
Sm-153	4.02E+7
Sm-155	3.11E+6
Sm-156	1.93E+6
Sn-127	2.78E+6
Sr-89	7.61E+7
Sr-90	7.21E+6
Sr-91	9.50E+7
Sr-92	1.01E+8
Tc-101	1.33E+8
Tc-104	1.05E+8
Tc-99m	1.29E+8
Te-127	6.81E+6
Te-127m	1.13E+6
Te-129	2.40E+7
Te-129m	4.87E+6
Te-131	6.54E+7
Te-131m	1.57E+7
Te-132	1.12E+8
Te-133	8.66E+7
Te-133m	7.12E+7
Te-134	1.41E+8
U-239	1.66E+9
Xe-131m	1.08E+6
Xe-133	1.60E+8
Xe-133m	5.05E+6
Xe-135	4.84E+7
Xe-135m	3.36E+7
Xe-138	1.36E+8
Y-90	7.49E+6
Y-91	9.87E+7
Y-91m	5.51E+7
Y-92	1.02E+8
Y-93	7.73E+7
Y-94	1.23E+8

Table 3.4.3-1 Core Inventory (Cont.)

Nuclide	Core Inventory (Curies)
Y-95	1.28E+8
Zr-95	1.33E+8
Zr-97	1.26E+8

Table 3.4.3-2 provides a description of the release characteristics evaluated in this analysis.

Table 3.4.3-2 Release Descriptions

Release Category	Representative Bins	MACCS2 Run Code	Plume Number	Energy Level (cal/sec)	Energy Level (W)	Release Height (m)	Time of Release (hr)	Duration (hr)	Alarm Delay (hr)
Variable			**NUMREL**		**PLHEAT**	**PLHITE**	**PDELAY**	**PLUDUR**	**OALARM**
INTACT	BV21	A	1	454	1.90E+03	43.7	4	4	4
INTACT	BV21	A	2	262.84	1.10E+03	43.7	8	20	4
VSEQ-ECF	BV19	B	1	3.75E+07	1.57E+08	3.2	2	0.5	1
SGTR-ECF	BV18	C	1	8.48E+07	3.55E+08	26.82	8	0.5	1
DCH-ECF	BV1, BV3	D	1	6.59E+07	2.76E+08	43.7	3	4	1
VSEQ-SECF	BV20	E	1	1.00E+06	4.19E+06	3.2	3	1	1
LOCI-SECF	BV7	F	1	2.15E+06	9.00E+06	12	1.5	0.5	1
LOCI-SECF	BV7	F	2	1.12E+06	4.69E+06	12	2	9.5	1
BV5-SECF	BV5	K	1	2.15E+06	9.00E+06	43.7	1.5	0.5	1
BV5-SECF	BV5	K	2	1.12E+06	4.69E+06	43.7	2	9.5	1
Large-Late	BV10, BV12	G	1	6.59E+07	2.76E+08	43.7	10	0.5	4
Large-Late	BV10, BV12	G	2	1.27E+07	5.32E+07	43.7	10.5	3	4
Small-Late	BV13, BV15	H	1	1.31E+07	5.49E+07	43.7	25	0.5	4
Small-Late	BV13, BV15	H	2	2.63E+06	1.10E+07	43.7	25.5	9.5	4
H2 Burn-Late	BV9	I	1	6.59E+07	2.76E+08	43.7	10	0.5	4
H2 Burn-Late	BV9	I	2	1.27E+07	5.32E+07	43.7	10.5	3.5	4
BMMT-Late	BV17	J	1	6.59E+07	2.76E+08	0	24	1	4

3.4.4 Emergency Response

A reactor scram signal begins each evaluated accident sequence. A General Emergency is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public. Therefore, the timing of the General Emergency declaration is sequence specific and alarms range from 1 to 4 hours for the release sequences evaluated.

The MACCS2 User's Guide input parameters of 95 percent of the population within 10 miles of the plant [Emergency Planning Zone (EPZ)] evacuating and 5 percent not evacuating were employed. These values have been used in similar studies (e.g., Hatch, Calvert Cliffs, (SNOC 2000) and (BGE 1998)) and are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the EPZ.

The evacuation speed was calculated by comparing the travel time estimates to the travel distances required. The Aliquippa/Hopewell area has the greatest population density in the EPZ, requires the longest evacuation time, and is only a few miles from the edge of the EPZ. It follows that the slowest and most conservative evacuation speeds would occur in this area. Based on the published evacuation routes and the population distribution in the area, a typical travel distance to the edge of the EPZ from this area is approximately 3 miles. Using the worst case evacuation time (inclement weather and persons without transportation) of 6¼ hours an average evacuation speed of 0.2 m/s was determined.

Three evacuation sensitivity cases were also performed to determine the impact of evacuation assumptions. One sensitivity case reduced the evacuation speed by a factor of four (0.05 m/sec) and the second increased the speed to 2.24 m/s (5 mph). The third sensitivity case assumed an increase by a factor of 1.5 in the alarm time, thus delaying the commencement of physical evacuation. The results are discussed in Section 8.

3.4.5 Meteorological Data

Each year of meteorological data consists of 8,760 weather data sets of hourly recordings of wind direction, wind speed, atmospheric stability, and accumulated precipitation. The data were from the Beaver Valley Power Station site weather facility for the years 2001, 2002, 2003, 2004, and 2005. MACCS2 does not permit missing data, so bad or missing data were filled in with National Oceanic and Atmospheric Administration (NOAA) data from the Pittsburgh International Airport (nearest most complete source of data) obtained from the NOAA Internet website. The approach used in this analysis was to perform MACCS2 analyses for each of the years for which meteorological data was gathered and combine the results after the MACCS2 analyses rather than before. Due to the consideration of five years of weather data, it is assumed that the average result from the analysis would be considered typical and representative. No one year was found to be conservative with respect to all release sequences.

3.5 SEVERE ACCIDENT RISK RESULTS

Using the MACCS2 code, the dose and economic costs associated with a severe accident at Beaver Valley was calculated for each of the years for which meteorological data was gathered. This information is provided below in Table 3.5-1 and Table 3.5-2, respectively. The average value of the yearly result for each release category was used in remainder of the analysis to represent the dose and cost for each of the specific release categories.

Table 3.5-1 Total L-EFFECTIVE LIFE Dose in Sieverts

Release Category	MACCS2 Run Code	BVPS Composite Weather Sensitivity Results					
		2001	2002	2003	2004	2005	Average
INTACT	A	8	7	8	7	7	8
ECF							
VSEQ	B	50,400	47,200	51,000	53,600	40,800	48,600
SGTR	C	44,500	41,400	43,800	46,500	37,000	42,640
DCH	D	86,800	84,800	86,600	76,400	77,600	82,440
SECF							
VSEQ	E	50,500	48,000	47,800	46,900	44,800	47,600
LOCI	F	35,200	35,500	33,200	34,000	36,400	34,860
BV5	K	43,800	39,800	41,300	41,000	42,700	41,720
LATE							
Large	G	1,530	1,440	1,780	1,600	1,450	1,560
Small	H	20,200	19,200	18,800	18,600	20,500	19,460
H2 Burn	I	19,300	17,200	17,600	16,300	17,900	17,660
BMMT	J	7,680	7,250	7,200	7,990	6,990	7,422

Table 3.5-2 Total Economic Costs in Dollars

Release Category	MACCS2 Run Code	BVPS Composite Weather Sensitivity Results					
		2001	2002	2003	2004	2005	Average
INTACT	A	6.400E+03	5.600E+03	5.590E+03	1.000E+04	7.510E+03	7.020E+03
ECF							
VSEQ	B	3.530E+10	3.260E+10	3.100E+10	3.350E+10	3.390E+10	3.326E+10
SGTR	C	4.280E+10	3.790E+10	3.580E+10	4.080E+10	3.840E+10	3.914E+10
DCH	D	4.800E+10	5.010E+10	5.010E+10	4.400E+10	5.000E+10	4.844E+10
SECF							
SGTR	E	2.540E+10	2.560E+10	2.690E+10	2.440E+10	2.920E+10	2.630E+10
LOCI	F	2.650E+10	2.520E+10	2.570E+10	2.460E+10	2.840E+10	2.608E+10
BV5	K	1.130E+10	1.070E+10	1.190E+10	1.050E+10	1.240E+10	1.136E+10
LATE							
Large	G	1.180E+08	1.260E+08	1.430E+08	1.590E+08	1.310E+08	1.354E+08
Small	H	1.090E+10	1.010E+10	1.150E+10	1.040E+10	1.170E+10	1.092E+10
H2 Burn	I	6.670E+09	6.220E+09	6.460E+09	5.600E+09	5.900E+09	6.170E+09
BMMT	J	4.380E+09	4.360E+09	5.480E+09	4.450E+09	4.700E+09	4.674E+09

3.6 MAJOR PRA MODELING DIFFERENCES BETWEEN BVPS UNIT 1 AND UNIT 2

Listed below are some major design differences between the BVPS Units that are accounted for in the PRA models. In addition, key differences in the BVPS PRA models were also previously docketed in Attachment B of the following letter.

- Pearce/USNRC, Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66 and BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests Nos. 306 and 176, dated October 29, 2004, Serial L-04-141.

1. Unit 1 has an additional feedwater pump (Dedicated AFW Pump) powered off the ERF diesel generator, which can be used during an SBO. This pump can provide secondary heat removal even if the SG are water solid, so it is not dependant on battery life. Unit 2 only has the Turbine-Driven AFW Pump, which fail if the SG goes water solid, so it is dependent on battery life during SBO conditions. Plant specific SBO MAAP analyses show that with the DAFW pump, as long as the RCP seal LOCA is initially less than 182 gpm and operators cooldown and depressurize the RCS, Unit 1 will not melt or uncover the core during a 48 hour period following the SBO. At Unit 2, this is not the case, and the core will uncover and melt during a 48 hour period following the SBO.

2. The Unit 1 Emergency DC Battery Rooms are constructed with concrete block walls, which have limited seismic capacity. At Unit 2 the Emergency DC Battery Rooms are constructed with reinforced concrete walls that have significant seismic capacity.

3. At Unit 1 the steam generators were replaced during 1RO17 and therefore have about half of the SGTR initiating event frequency of the Unit 2 value (2.09E-03 vs. 4.82E-03).

4. The Unit 2 RWST volume is about twice the size of the Unit 1 volume (~ 860,000 gal vs. ~440,000 gal).

5. At Unit 1 the atmospheric steam dump valves have a higher capacity than Unit 2 (294,400 lbs/hr vs. 235,000 lbs/hr) and therefore the RCS cooldown and depressurization using the secondary heat removal system success criteria is different. Unit 1 only requires 1 ASDV and feedwater to the associated SG, while Unit 2 requires 2 ASDVs with feedwater to both associated SGs.

6. Unit 2 normally has two Service Water pumps in service, while Unit 1 normally only has one River Water pump in service. Therefore, since the success criteria for both Units is one River Water/Service Water pump, there is a lower system failure probability at Unit 2 due to not having to start a standby pump given the failure of a running pump.

4 COST OF SEVERE ACCIDENT RISK / MAXIMUM BENEFIT

Cost/benefit evaluation of SAMAs is based upon the cost of implementation of a SAMA compared to the averted onsite and offsite costs resulting from the implementation of that SAMA. The methodology used for this evaluation was based upon the NRC's guidance for the performance of cost-benefit analyses (Reference 20). This guidance involves determining the net value for each SAMA according to the following formula:

Net Value = (APE + AOC + AOE + AOSC) – COE

where APE = present value of averted public exposure ($),
AOC = present value of averted offsite property damage costs ($),
AOE = present value of averted occupational exposure ($),
AOSC = present value of averted onsite costs ($)
COE = cost of enhancement ($).

If the net value of a SAMA is negative, the cost of implementing the SAMA is larger than the benefit associated with the SAMA and is not considered beneficial. The derivation of each of these costs is described in below.

The following specific values were used for various terms in the analyses:

Present Worth

The present worth was determined by:

$$PW = \frac{1 - e^{-rt}}{r}$$

Where:

r is the **discount rate = 7%** (assumed throughout these analyses)
t is the **duration of the license renewal = 20 years**
PW is the present worth of a string of annual payments = **10.76**

Dollars per REM

The conversion factor used for assigning a monetary value to on-site and off-site exposures was **$2,000/person-rem averted**. This is consistent with the NRC's regulatory analysis guidelines presented in and used throughout NUREG/BR-0184, Reference 20.

On-site Person REM per Accident

The occupational exposure associated with severe accidents was assumed to be **23,300 person-rem/accident.** This value includes a short-term component of 3,300 person-rem/accident and a long-term component of 20,000 person-rem/accident. These estimates are consistent with the "best estimate" values presented in Section 5.7.3 of Reference 20. In the cost/benefit analyses, the accident-related on-site exposures were calculated using the best estimate exposure components applied over the on-site cleanup period.

On-site Cleanup Period

In the cost/benefit analyses, the accident-related on-site exposures were calculated over a **10-year cleanup period**.

Present Worth On-site Cleanup Cost per Accident

The estimated cleanup cost for severe accidents was assumed to be **$1.5E+09/accident** (undiscounted). This value was derived by the NRC in Reference 20, Section 5.7.6.1, Cleanup and Decontamination. This cost is the sum of equal annual costs over a 10-year cleanup period. At a 7% discount rate, the present value of this stream of costs is **$1.1E+09**.

4.1 OFF-SITE EXPOSURE COST

Accident-Related Off-Site Dose Costs

Offsite doses were determined using the consolidated MACCS2 model developed for BVPS Units 1 and 2. Costs associated with these doses were calculated using the following equation:

$$APE = \left(F_S D_{P_S} - F_A D_{P_A}\right) R \frac{1 - e^{-rt_f}}{r} \qquad (1)$$

where:

APE = monetary value of accident risk avoided due to population doses, after discounting

R = monetary equivalent of unit dose, ($/person-rem)

F = accident frequency (events/yr)
D_P = population dose factor (person-rems/event)
S = status quo (current conditions)
A = after implementation of proposed action
r = real discount rate
t_f = analysis period (years).

Using the values for r, t_f, and R given above:

$$W_P = (\$2.15E + 4)\left(F_S D_{P_S} - F_A D_{P_A}\right)$$

4.2 OFF-SITE ECONOMIC COST

Accident-Related Off-Site Property Damage Costs

Offsite damage was determined using the MACCS2 model developed for BVPS-2. Costs associated with these damages were calculated using the following equation:

$$AOC = \left(F_S P_{D_S} - F_A P_{D_A}\right)\frac{1-e^{-rt_f}}{r}$$

where:

AOC = monetary value of accident risk avoided due to offsite property damage, after discounting
F = accident frequency (events/yr)
P_D = offsite property loss factor (dollars/event)
r = real discount rate
t_f = analysis period (years).

4.3 ON-SITE EXPOSURE COST

Methods for Calculating Averted Costs Associated with Onsite Accident Dose Costs

a) **Immediate Doses** (at time of accident and for immediate management of emergency)

For the case where the plant is in operation, the equations in Reference 20 can be expressed as:

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

where:

W_{IO} = monetary value of accident risk avoided due to immediate doses, after discounting
R = monetary equivalent of unit dose, ($/person-rem)
F = accident frequency (events/yr)
D_{IO} = immediate occupational dose (person-rems/event)
S = status quo (current conditions)
A = after implementation of proposed action
r = real discount rate
t_f = analysis period (years).

The values used are:
R = $2000/person rem
r = .07
D_{IO} = 3,300 person-rems /accident (best estimate)

The license extension time of 20 years is used for t_f.

For the basis discount rate, assuming F_A is zero, the best estimate of the limiting savings is

$$\begin{aligned} W_{IO} &= (F_S D_{IO_S}) R \frac{1-e^{-rt_f}}{r} \\ &= 3300 * F * \$2000 * \frac{1-e^{-.07*20}}{.07} \\ &= F * \$6{,}600{,}000 * 10.763 \\ &= F * \$0.71E + 8, (\$). \end{aligned}$$

b) **Long-Term Doses** (process of cleanup and refurbishment or decontamination)

For the case where the plant is in operation, the equations in Reference 20 can be expressed as:

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

where:

W_{IO} = monetary value of accident risk avoided long term doses, after discounting, \$

m = years over which long-term doses accrue.

The values used are:

R = \$2000/person rem

r = .07

D_{LTO} = 20,000 person-rem /accident (best estimate)

m = "as long as 10 years"

The license extension period of 20 years is used for t_f.

For the discount rate of 7%, assuming F_A is zero, the best estimate of the limiting savings is

$$\begin{aligned} W_{LTO} &= (F_S D_{LTO_S}) R * \frac{1-e^{-rt_f}}{r} * \frac{1-e^{-rm}}{rm} \\ &= (F_S 20000)\$2000 * \frac{1-e^{-.07*20}}{.07} * \frac{1-e^{-.07*10}}{.07*10} \\ &= F_S * \$40{,}000{,}000 * 10.763 * 0.719 \\ &= F_S * \$3.10E+8, (\$). \end{aligned}$$

c) **Total Accident-Related Occupational (On-site) Exposures**

Combining equations (1) and (2) above, using delta (Δ) to signify the difference in accident frequency resulting from the proposed actions, and using the above numerical values, the long term accident related on-site (occupational) exposure avoided (AOE) is:

Best Estimate:

$$AOE = W_{IO} + W_{LTO} = F * \$(0.71 + 3.1)E + 8 = F * \$3.81E + 8 \ (\$)$$

4.4 ON-SITE ECONOMIC COST

Methods for Calculation of Averted Costs Associated with Accident-Related On-Site Property Damage

a) **Cleanup/Decontamination**

Reference 20 assumes a total cleanup/decontamination cost of \$1.5E+9 as a reasonable estimate and this same value was adopted for these analyses. Considering a 10-year cleanup period, the present value of this cost is:

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

Where

PV_{CD} = Present value of the cost of cleanup/decontamination.
C_{CD} = Total cost of the cleanup/decontamination effort.
m = Cleanup period.
r = Discount rate.

Based upon the values previously assumed:

$$PV_{CD} = \left(\frac{\$1.5E+9}{10}\right)\left(\frac{1-e^{-.07*10}}{.07}\right)$$

$$PV_{CD} = \$1.079E+9$$

This cost is integrated over the term of the proposed license extension as follows

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

Based upon the values previously assumed:

$$U_{CD} = \$1.079E+9\,[10.763]$$
$$U_{CD} = \$1.161E+10$$

b) **Replacement Power Costs**

Replacement power costs, U_{RP}, are an additional contributor to onsite costs. These are calculated in accordance with NUREG/BR-0184, Section 5.6.7.2.[1] Since replacement power will be needed for that time period following a severe accident, for the remainder of the expected generating plant life, long-term power replacement calculations have been used. The calculations are based on the 910 MWe reference plant, and are appropriately scaled for the 977 MWe BVPS-2. The present value of replacement power is calculated as follows:

$$PV_{RP} = \left(\frac{(\$1.2E+8)\dfrac{(Ratepwr)}{(910MWe)}}{r} \right) \left(1 - e^{-rt_f}\right)^2$$

Where

PV_{RP} = Present value of the cost of replacement power for a single event.
t_f = analysis period (years).
r = Discount rate.
Ratepwr = Rated power of the unit

The \$1.2E+8 value has no intrinsic meaning but is a substitute for a string of non-constant replacement power costs that occur over the lifetime of a "generic" reactor after an event (from Reference 20). This equation was developed per NUREG/BR-0184 for discount rates between 5% and 10% only.

For discount rates between 1% and 5%, Reference 20 indicates that a linear interpolation is appropriate between present values of \$1.2E+9 at 5% and \$1.6E+9 at 1%. So for discount rates in this range the following equation was used to perform this linear interpolation.

$$PV_{RP} = \left\{ (\$1.6E+9) - \left(\frac{[(\$1.6E+9) - (\$1.2E+9)]}{[5\% - 1\%]} * [r_s - 1\%] \right) \right\} * \left\{ \frac{Ratepwr}{910MWe} \right\}$$

Where

r_s = Discount rate (small), between 1% and 5%.

[1] The section number for Section 5.6.7.2 apparently contains a typographical error. This section is a subsection of 5.7.6 and follows 5.7.6.1. However, the section number as it appears in the NUREG will be used in this document.

Ratepwr = Rated power of the unit

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

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

Where
U_{RP} = Present value of the cost of replacement power over the life of the facility.

Again, this equation is only applicable in the range of discount rates from 5% to 10%. NUREG/BR-0184 states that for lower discount rates, linear interpolations for U_{RP} are recommended between \$1.9E+10 at 1% and \$1.2E+10 at 5%. The following equation was used to perform this linear interpolation:

$$U_{RP} = \left\{(\$1.9E+10) - \left(\frac{[(\$1.9E+10) - (\$1.2E+10)]}{[5\% - 1\%]} * [r_s - 1\%]\right)\right\} * \left\{\frac{Ratepwr}{910MWe}\right\}$$

Where
r_s = Discount rate (small), between 1% and 5%.
Ratepwr = Rated power of the unit

c) **Repair and Refurbishment**

It is assumed that the plant would not be repaired/refurbished; therefore, there is not contribution to averted onsite costs from this source.

d) **Total Onsite Property Damage Costs**

The net present value of averted onsite damage costs is, therefore:

$$AOSC = F * (U_{CD} + U_{RP})$$

Where F = Annual frequency of the event.

4.5 TOTAL COST OF SEVERE ACCIDENT RISK / MAXIMUM BENEFIT

Cost/benefit evaluation of the maximum benefit is baseline risk of the plant converted dollars by summing the contributors to cost.

Maximum Benefit Value = (APE + AOC + AOE + AOSC)

where APE = present value of averted public exposure ($),
AOC = present value of averted offsite property damage costs ($),
AOE = present value of averted occupational exposure ($),
AOSC = present value of averted onsite costs ($)

For Beaver Valley Unit 2, this value is $5,097,992 as shown below.

Parameter	Unit 2 Present Dollar Value ($)
Averted Public Exposure	$1,203,099
Averted offsite costs	$3,403,247
Averted occupational exposure	$9,146
Averted onsite costs	$482,500
Total	$5,097,992

5 SAMA IDENTIFICATION

A list of SAMA candidates was developed by reviewing the major contributors to CDF and population dose based on the plant-specific risk assessment and the standard PWR list of enhancements from Reference 24 (NEI 05-01). This section discusses the SAMA selection process and its results.

5.1 PRA IMPORTANCE

The top core damage sequences and the components/systems having the greatest potential for risk reduction were examined to determine whether additional SAMAs could be identified from these sources.

Use of Importance Measures
Risk reduction worth (RRW) of the components in the baseline model was used to identify those basic events that could have a significant potential for reducing risk. Components with risk reduction worth (RRW) >1.005 were identified as the most important components. A similar review was performed on a system basis. The components and systems were reviewed to ensure that each component and system is covered by an existing SAMA item or added to the list if not.

Use of the Top Sequences

The top sequences leading to core melt were reviewed. A key result is that no single PRA sequence makes up a large fraction of the core damage frequency. The sequences were reviewed to ensure that initiators and failures identified in the sequences were either covered by existing SAMAs or added to the list of plant specific SAMAs.

5.2 PLANT IPE

The Beaver Valley Unit 2 PRA identified some potential vulnerabilities. Corresponding enhancements have been considered.

As noted in the IPE, large fractions of the CDF are associated with RCP seal LOCA and station blackout. Other major contributors are containment bypass/isolation failure, loss of switchgear HVAC and transients without scram.

These accident categories are not always mutually exclusive. One of the top ranked sequences illustrates this clearly. A loss of offsite power will challenge the onsite emergency power system. Failure of both emergency diesels would result in a station blackout. The consequential loss of seal injection and component cooling water to the reactor coolant pumps (RCP) thermal barrier could eventually lead to a RCP seal LOCA. Station blackout and RCP seal LOCA are both conditions of this scenario that can result in core uncovery and damage.

In order to determine vulnerabilities, the major accident categories were evaluated along with the top-ranking sequences contributing to CDF. For a summary of the PRA results and a detailed discussion of the top-ranked sequences refer to Section 1.4.

The Beaver Valley Unit 2 potential enhancements are listed in Table 5.2-1.

Table 5.2-1. Beaver Valley Unit 2 IPE Potential Enhancements

Vulnerability	Procedure or Design Enhancement	Impact of Enhancement	CDF Importance		Status
			Percent of CDF	Risk * Achievement Worth	
AC Power Generation Capability for Station Blackout	Provide Beaver Valley Units 1 and 2 with 4,160 V Bus Crosstie Capability	Adds a success path for blackout on Unit 2 when both Unit 1 diesel generators work, and vice versa	25.3	301	Intent Met. SAMAs 9, 11, 12, 154
RCP Seal Cooling for Station Blackout	Potential modifications under review	Reduced frequency of RCP seal LOCA resulting from blackout	18.8	**	Intent Met. SAMA 158
Loss of Emergency Switchgear Room HVAC	Enhanced Loss of HVAC Procedures	Confidence that operators will prevent thermal damage to switchgear	17.1	19,428	Intent Met. SAMA 157, further analysis shows that there is a long time for installation of temporary ventilation.
Fast 4,160 V Bus Transfer Failure	Explicit Procedure and Training on breaker repair or change out	Reduced frequency that breaker failures will challenge diesel generators	8.0	1.6	Intent Met SAMA 21
Pressurizer PORV sticking open after loss of offsite power	Eliminate challenge by defeating the 100% load rejection capability	Reduced frequency of pressurizer PORV sticking open	7.2	3.1	Intent Met. SAMA 156, turbine trip above 30% causes reactor trip.
Battery Capacity for steam generator level instruments for station blackout	Enhance procedures on shedding loads or using portable battery chargers. One train of the battery chargers will be powered from the site operable emergency diesel generator once the Station Blackout Unit crosstie modification is complete.	Extended operating time for steam generator level instruments for loss of all AC power scenarios	6.8	337	SAMA 3, 159
Reactor Trip breaker failure	Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	4.2	5.9	SAMA 155, Analysis shows that actions outside the control room cannot be performed quickly enough. PRA updates have reduced the contribution from ATWS events.

Note: * The risk achievement worth is the factor increase in CDF that would be realized if the failure probability of the affected system were increased to 1.0.
** Included in the AC power generation capability for station blackout risk achievement worth value.

5.3 PLANT IPEEE

Potential improvements to reduce the risk in dominant fire zones and to reduce seismic risk and risk from other external events were evaluated in the Beaver Valley Unit 2 IPEEE. The list of candidate improvements and their status is documented in the IPEEE and reproduced in Table 3.1.2-1 in this report.

5.4 INDUSTRY SAMA CANDIDATES

The generic PWR enhancement list from Table 14 of Reference 24 was included in the list of Phase I SAMA candidates to assure adequate consideration of potential enhancements identified by other industry studies.

5.5 PLANT STAFF INPUT TO SAMA CANDIDATES

The Beaver Valley plant staff provided plant specific items that were included in the evaluation. These are identified in the list of SAMA candidates by their source.

5.6 LIST OF PHASE I SAMA CANDIDATES

Table 5.6-1 provides the combined list of potential SAMA candidates considered in the Beaver Valley Unit 2 SAMA analysis. From this table it can be seen that 190 SAMA candidates were identified for consideration.

Table 5.6-1 List of SAMA Candidates

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
1	Provide additional DC battery capacity.	Extended DC power availability during an SBO.	AC/DC	1, C
2	Replace lead-acid batteries with fuel cells.	Extended DC power availability during an SBO.	AC/DC	1
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	AC/DC	1, C
4	Improve DC bus load shedding.	Extended DC power availability during an SBO.	AC/DC	1
5	Provide DC bus cross-ties.	Improved availability of DC power system.	AC/DC	1
6	Provide additional DC power to the 120/240V vital AC system.	Increased availability of the 120 V vital AC bus.	AC/DC	1
7	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.	AC/DC	1
8	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.	AC/DC	1
9	Provide an additional diesel generator.	Increased availability of on-site emergency AC power.	AC/DC	1
10	Revise procedure to allow bypass of diesel generator trips.	Extended diesel generator operation.	AC/DC	1
11	Improve 4.16-kV bus cross-tie ability.	Increased availability of on-site AC power.	AC/DC	1, A
12	Create AC power cross-tie capability with other unit (multi-unit site)	Increased availability of on-site AC power.	AC/DC	1, A
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	AC/DC	1
14	Install a gas turbine generator.	Increased availability of on-site AC power.	AC/DC	1
15	Install tornado protection on gas turbine generator.	Increased availability of on-site AC power.	AC/DC	1
16	Improve uninterruptible power supplies.	Increased availability of power supplies supporting front-line equipment.	AC/DC	1
17	Create a cross-tie for diesel fuel oil (multi-unit site).	Increased diesel generator availability.	AC/DC	1
18	Develop procedures for replenishing diesel fuel oil.	Increased diesel generator availability.	AC/DC	1
19	Use fire water system as a backup source for diesel cooling.	Increased diesel generator availability.	AC/DC	1
20	Add a new backup source of diesel cooling.	Increased diesel generator availability.	AC/DC	1
21	Develop procedures to repair or replace failed 4 KV breakers.	Increased probability of recovery from failure of breakers that transfer 4.16 kV non-emergency buses from unit station service transformers.	AC/DC	1, A
22	In training, emphasize steps in recovery of off-site power after an SBO.	Reduced human error probability during off-site power recovery.	AC/DC	1
23	Develop a severe weather conditions procedure.	Improved off-site power recovery following external weather-related events.	AC/DC	1
24	Bury off-site power lines.	Improved off-site power reliability during severe weather.	AC/DC	1
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	Core Cooling	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	Core Cooling	1
27	Revise procedure to allow operators to inhibit automatic vessel depressurization in non-ATWS scenarios.	Extended HPCI and RCIC operation.	Core Cooling	1
28	Add a diverse low pressure injection system.	Improved injection capability.	Core Cooling	1
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	Core Cooling	1
30	Improve ECCS suction strainers.	Enhanced reliability of ECCS suction.	Core Cooling	1
31	Add the ability to manually align emergency core cooling system recirculation.	Enhanced reliability of ECCS suction.	Core Cooling	1
32	Add the ability to automatically align emergency core cooling system to recirculation mode upon refueling water storage tank depletion.	Enhanced reliability of ECCS suction.	Core Cooling	1
33	Provide hardware and procedure to refill the reactor water storage tank once it reaches a specified low level.	Extended reactor water storage tank capacity in the event of a steam generator tube rupture.	Core Cooling	1
34	Provide an in-containment reactor water storage tank.	Continuous source of water to the safety injection pumps during a LOCA event, since water released from a breach of the primary system collects in the in-containment reactor water storage tank, and thereby eliminates the need to realign the safety injection pumps for long-term post-LOCA recirculation.	Core Cooling	1
35	Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	Extended reactor water storage tank capacity.	Core Cooling	1
36	Emphasize timely recirculation alignment in operator training.	Reduced human error probability associated with recirculation failure.	Core Cooling	1
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	Core Cooling	1
38	Change the in-containment reactor water storage tank suction from four check valves to two check and two air-operated valves.	Reduced common mode failure of injection paths.	Core Cooling	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injection systems.	Core Cooling	1
40	Provide capability for remote, manual operation of secondary side pilot-operated relief valves in a station blackout.	Improved chance of successful operation during station blackout events in which high area temperatures may be encountered (no ventilation to main steam areas).	Core Cooling	1
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	Core Cooling	1
42	Make procedure changes for reactor coolant system depressurization.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	Core Cooling	1
43	Add redundant DC control power for SW pumps.	Increased availability of SW.	Cooling Water	1
44	Replace ECCS pump motors with air-cooled motors.	Elimination of ECCS dependency on component cooling system.	Cooling Water	1
45	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.	Cooling Water	1
46	Add a service water pump.	Increased availability of cooling water.	Cooling Water	1
47	Enhance the screen wash system.	Reduced potential for loss of SW due to clogging of screens.	Cooling Water	1
48	Cap downstream piping of normally closed component cooling water drain and vent valves.	Reduced frequency of loss of component cooling water initiating events, some of which can be attributed to catastrophic failure of one of the many single isolation valves.	Cooling Water	1
49	Enhance loss of component cooling water (or loss of service water) procedures to facilitate stopping the reactor coolant pumps.	Reduced potential for reactor coolant pump seal damage due to pump bearing failure.	Cooling Water	1
50	Enhance loss of component cooling water procedure to underscore the desirability of cooling down the reactor coolant system prior to seal LOCA.	Reduced probability of reactor coolant pump seal failure.	Cooling Water	1
51	Additional training on loss of component cooling water.	Improved success of operator actions after a loss of component cooling water.	Cooling Water	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
52	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	Reduced effect of loss of component cooling water by providing a means to maintain the charging pump seal injection following a loss of normal cooling water.	Cooling Water	1
53	On loss of essential raw cooling water, proceduralize shedding component cooling water loads to extend the component cooling water heat-up time.	Increased time before loss of component cooling water (and reactor coolant pump seal failure) during loss of essential raw cooling water sequences.	Cooling Water	1
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	Cooling Water	1
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	Cooling Water	1
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	Cooling Water	1
57	Use existing hydro test pump for reactor coolant pump seal injection.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	Cooling Water	1
58	Install improved reactor coolant pump seals.	Reduced likelihood of reactor coolant pump seal LOCA.	Cooling Water	1
59	Install an additional component cooling water pump.	Reduced likelihood of loss of component cooling water leading to a reactor coolant pump seal LOCA.	Cooling Water	1
60	Prevent makeup pump flow diversion through the relief valves.	Reduced frequency of loss of reactor coolant pump seal cooling if spurious high pressure injection relief valve opening creates a flow diversion large enough to prevent reactor coolant pump seal injection.	Cooling Water	1
61	Change procedures to isolate reactor coolant pump seal return flow on loss of component cooling water, and provide (or enhance) guidance on loss of injection during seal LOCA.	Reduced frequency of core damage due to loss of seal cooling.	Cooling Water	1
62	Implement procedures to stagger high pressure safety injection pump use after a loss of service water.	Extended high pressure injection prior to overheating following a loss of service water.	Cooling Water	1
63	Use fire prevention system pumps as a backup seal injection and high pressure makeup source.	Reduced frequency of reactor coolant pump seal LOCA.	Cooling Water	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	Cooling Water	1
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	Feedwater/Condensate	1
66	Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	Increased availability of feedwater.	Feedwater/Condensate	1
67	Install an independent diesel for the condensate storage tank makeup pumps.	Extended inventory in CST during an SBO.	Feedwater/Condensate	1
68	Add a motor-driven feedwater pump.	Increased availability of feedwater.	Feedwater/Condensate	1
69	Install manual isolation valves around auxiliary feedwater turbine-driven steam admission valves.	Reduced dual turbine-driven pump maintenance unavailability.	Feedwater/Condensate	1
70	Install accumulators for turbine-driven auxiliary feedwater pump flow control valves.	Eliminates the need for local manual action to align nitrogen bottles for control air following a loss of off-site power.	Feedwater/Condensate	1
71	Install a new condensate storage tank (auxiliary feedwater storage tank).	Increased availability of the auxiliary feedwater system.	Feedwater/Condensate	1
72	Modify the turbine-driven auxiliary feedwater pump to be self-cooled.	Improved success probability during a station blackout.	Feedwater/Condensate	1
73	Proceduralize local manual operation of auxiliary feedwater system when control power is lost.	Extended auxiliary feedwater availability during a station blackout. Also provides a success path should auxiliary feedwater control power be lost in non-station blackout sequences.	Feedwater/Condensate	1
74	Provide hookup for portable generators to power the turbine-driven auxiliary feedwater pump after station batteries are depleted.	Extended auxiliary feedwater availability.	Feedwater/Condensate	1
75	Use fire water system as a backup for steam generator inventory.	Increased availability of steam generator water supply.	Feedwater/Condensate	1
76	Change failure position of condenser makeup valve if the condenser makeup valve fails open on loss of air or power.	Allows greater inventory for the auxiliary feedwater pumps by preventing condensate storage tank flow diversion to the condenser.	Feedwater/Condensate	1
77	Provide a passive, secondary-side heat-rejection loop consisting of a condenser and heat sink.	Reduced potential for core damage due to loss-of-feedwater events.	Feedwater/Condensate	1
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	Feedwater/Condensate	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
79	Replace existing pilot-operated relief valves with larger ones, such that only one is required for successful feed and bleed.	Increased probability of successful feed and bleed.	Feedwater/Condensate	1
80	Provide a redundant train or means of ventilation.	Increased availability of components dependent on room cooling.	HVAC	1
81	Add a diesel building high temperature alarm or redundant louver and thermostat.	Improved diagnosis of a loss of diesel building HVAC.	HVAC	1
82	Stage backup fans in switchgear rooms.	Increased availability of ventilation in the event of a loss of switchgear ventilation.	HVAC	1
83	Add a switchgear room high temperature alarm.	Improved diagnosis of a loss of switchgear HVAC.	HVAC	1
84	Create ability to switch emergency feedwater room fan power supply to station batteries in a station blackout.	Continued fan operation in a station blackout.	HVAC	1
85	Provide cross-unit connection of uninterruptible compressed air supply.	Increased ability to vent containment using the hardened vent.	IA/Nitrogen	1
86	Modify procedure to provide ability to align diesel power to more air compressors.	Increased availability of instrument air after a LOOP.	IA/Nitrogen	1
87	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 service water cooling.	IA/Nitrogen	1
88	Install nitrogen bottles as backup gas supply for safety relief valves.	Extended SRV operation time.	IA/Nitrogen	1
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	IA/Nitrogen	1
90	Create a reactor cavity flooding system.	Enhanced debris cool ability, reduced core concrete interaction, and increased fission product scrubbing.	Containment Phen	1
91	Install a passive containment spray system.	Improved containment spray capability.	Containment Phen	1
92	Use the fire water system as a backup source for the containment spray system.	Improved containment spray capability.	Containment Phen	1
93	Install an unfiltered, hardened containment vent.	Increased decay heat removal capability for non-ATWS events, without scrubbing released fission products.	Containment Phen	1
94	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.	Containment Phen	1
95	Enhance fire protection system and standby gas treatment system hardware and procedures.	Improved fission product scrubbing in severe accidents.	Containment Phen	1
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	Containment Phen	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
97	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 basemat.	Containment Phen	1
98	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.	Containment Phen	1
99	Strengthen primary/secondary containment (e.g., add ribbing to containment shell).	Reduced probability of containment over-pressurization.	Containment Phen	1
100	Increase depth of the concrete base mat or use an alternate concrete material to ensure melt-through does not occur.	Reduced probability of basemat melt-through.	Containment Phen	1
101	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.	Containment Phen	1
102	Construct a building to be connected to primary/secondary containment and maintained at a vacuum.	Reduced probability of containment over-pressurization.	Containment Phen	1
103	Institute simulator training for severe accident scenarios.	Improved arrest of core melt progress and prevention of containment failure.	Containment Phen	1
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	Containment Phen	1
105	Delay containment spray actuation after a large LOCA.	Extended reactor water storage tank availability.	Containment Phen	1
106	Install automatic containment spray pump header throttle valves.	Extended time over which water remains in the reactor water storage tank, when full containment spray flow is not needed.	Containment Phen	1
107	Install a redundant containment spray system.	Increased containment heat removal ability.	Containment Phen	1
108	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.	Containment Phen	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
109	Install a passive hydrogen control system.	Reduced hydrogen detonation potential.	Containment Phen	1
110	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.	Containment Phen	1
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	Containment Bypass	1
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	Containment Bypass	1
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	Containment Bypass	1
114	Install self-actuating containment isolation valves.	Reduced frequency of isolation failure.	Containment Bypass	1
115	Locate residual heat removal (RHR) inside containment	Reduced frequency of ISLOCA outside containment.	Containment Bypass	1
116	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.	Containment Bypass	1
117	Revise EOPs to improve ISLOCA identification.	Increased likelihood that LOCAs outside containment are identified as such. A plant had a scenario in which an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment.	Containment Bypass	1
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	Containment Bypass	1
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	Containment Bypass	1
120	Replace steam generators with a new design.	Reduced frequency of steam generator tube ruptures.	Containment Bypass	1
121	Increase the pressure capacity of the secondary side so that a steam generator tube rupture would not cause the relief valves to lift.	Eliminates release pathway to the environment following a steam generator tube rupture.	Containment Bypass	1
122	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture	Enhanced depressurization capabilities during steam generator tube rupture.	Containment Bypass	1
123	Proceduralize use of pressurizer vent valves during steam generator tube rupture sequences.	Backup method to using pressurizer sprays to reduce primary system pressure following a steam generator tube rupture.	Containment Bypass	1
124	Provide improved instrumentation to detect steam generator tube ruptures, such as Nitrogen-16 monitors).	Improved mitigation of steam generator tube ruptures.	Containment Bypass	1
125	Route the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove most of the fission products.	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
126	Install a highly reliable (closed loop) steam generator shell-side heat removal system that relies on natural circulation and stored water sources	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1
127	Revise emergency operating procedures to direct isolation of a faulted steam generator.	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1
128	Direct steam generator flooding after a steam generator tube rupture, prior to core damage.	Improved scrubbing of steam generator tube rupture releases.	Containment Bypass	1
129	Vent main steam safety valves in containment.	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	ATWS	1
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	ATWS	1
132	Provide an additional control system for rod insertion (e.g., AMSAC).	Improved redundancy and reduced ATWS frequency.	ATWS	1
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	ATWS	1
134	Revise procedure to bypass MSIV isolation 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 human error probabilities.	ATWS	1
135	Revise procedure to allow override of low pressure core injection during an ATWS event.	Allows immediate control of low pressure core injection. On failure of high pressure core injection and condensate, some plants direct reactor depressurization followed by five minutes of automatic low pressure core injection.	ATWS	1
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	ATWS	1
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	ATWS	1
138	Improve inspection of rubber expansion joints on main condenser.	Reduced frequency of internal flooding due to failure of circulating water system expansion joints.	Internal Flooding	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
139	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	Prevents flood propagation.	Internal Flooding	1
140	Increase seismic ruggedness of plant components.	Increased availability of necessary plant equipment during and after seismic events.	Seismic Risk	1
141	Provide additional restraints for CO2 tanks.	Increased availability of fire protection given a seismic event.	Seismic Risk	1
142	Replace mercury switches in fire protection system.	Decreased probability of spurious fire suppression system actuation.	Fire Risk	1
143	Upgrade fire compartment barriers.	Decreased consequences of a fire.	Fire Risk	1
144	Install additional transfer and isolation switches.	Reduced number of spurious actuations during a fire.	Fire Risk	1
145	Enhance fire brigade awareness.	Decreased consequences of a fire.	Fire Risk	1
146	Enhance control of combustibles and ignition sources.	Decreased fire frequency and consequences.	Fire Risk	1
147	Install digital large break LOCA protection system.	Reduced probability of a large break LOCA (a leak before break).	Other	1
148	Enhance procedures to mitigate large break LOCA.	Reduced consequences of a large break LOCA.	Other	1
149	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.	Other	1
150	Improve maintenance procedures.	Improved prevention of core melt sequences by increasing reliability of important equipment.	Other	1
151	Increase training and operating experience feedback to improve operator response.	Improved likelihood of success of operator actions taken in response to abnormal conditions.	Other	1
152	Develop procedures for transportation and nearby facility accidents.	Reduced consequences of transportation and nearby facility accidents.	Other	1
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	Other	1
154	Provide Beaver Valley Units 1 and 2 with 4,160 V Bus Crosstie Capability	Adds a success path for blackout on Unit 2 when both Unit 1 diesel generators work, and vice versa	AC/DC	A
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	ATWS	A
156	Operate plant with all PORV block valves open or provide procedures to open block valves when Main Feedwater is lost.	Increased pressure relief capacity to prevent reactor vessel rupture during ATWS.	ATWS	A

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
157	Loss of Emergency Switchgear Room HVAC , Enhanced Loss of HVAC Procedures	Confidence that operators will prevent thermal damage to switchgear	HVAC	A
158	RCP Seal Cooling for Station Blackout, Potential modifications under review	Reduced frequency of RCP seal LOCA resulting from blackout	Cooling Water	A
159	Battery Capacity for steam generator level instruments for station blackout, Enhance procedures on shedding loads or using portable battery chargers. One train of the battery chargers will be powered from the site operable emergency diesel generator once the Station Blackout Unit crosstie modification is complete.	Extended operating time for steam generator level instruments for less of all AC power scenarios	AC/DC	A
160	Pressurizer PORV sticking open after loss of offsite power, Eliminate challenge by defeating the 100% load rejection capability	Reduced frequency of pressurizer PORV sticking open	Core Cooling	A
161	Fast 4,160 V Bus Transfer Failure, Explicit Procedure and Training on breaker repair or change out	Reduced frequency that breaker failures will challenge diesel generators	AC/DC	A
162	Provide a dedicated diesel driven feed water pump with supply tank to provide an additional source of water for SG tube coverage during SGTR events.	This would eliminate the LERF category and reduce all SGTR events to Small Early Releases.	Core Cooling	C
163	Modify Loss of DC AOP to proceduralize the use of backup battery chargers.	Provide better reliability of the DC busses.	AC/DC	C
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	Containment Bypass	C
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	Cooling Water	C
166	Provide additional emergency 125V DC battery capability.	Better coping for long term station blackouts	AC/DC	C
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	Seismic Risk	C
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	Fire Risk	C
169	Improve operator performance. Operator fails to align makeup to RWST - SGTR, secondary leak	Top 10 operator actions OPRWM1	Human Reliability	D
170	Improve operator performance. Operator fails to manually trip reactor - ATWS	Top 10 operator actions OPROT1	Human Reliability	D
171	Improve operator performance. Operator fails to realign main feedwater - no SI signal	Top 10 operator actions OPROF2	Human Reliability	D

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
172	Improve operator performance. Operator fails to initiate AFW following transient	Top 10 operator actions OPROS6	Human Reliability	D
173	Improve operator performance. Operator aligns spare battery charger 2-9 to 2-2	Top 10 operator actions OPRDC2	Human Reliability	D
174	Improve operator performance. Operator aligns spare battery charger 2-7 to 2-1	Top 10 operator actions OPRDC1	Human Reliability	D
175	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB2	Human Reliability	D
176	Improve operator performance. Operator fails to trip RCP during loss of CCP	Top 10 operator actions OPROC1	Human Reliability	D
177	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB1	Human Reliability	D
178	Improve operator performance. Operator fails to identify ruptured SG or initiate isolation	Top 10 operator actions OPRSL1	Human Reliability	D
179	Reduce risk contribution from fires originating in Zone CB-3, causing a total loss of main feedwater and auxiliary feedwater with subsequent failure of feed and bleed.	Elimination or improved mitigation of fires in this area.	Fire Risk	B
180	Reduce risk contribution from fires originating in zone CT-1, causing a total loss of service water.	Elimination or improved mitigation of fires in this area.	Fire Risk	B
181	Reduce risk contribution from fires originating in zone SB-4, causing a total loss of normal AC power with subsequent failure of emergency AC power and station crosstie leading to station blackout.	Elimination or improved mitigation of fires in this area.	Fire Risk	B
182	Reduce risk contribution from fires originating in zone CV-1, causing failure of service water	Elimination or improved mitigation of fires in this area.	Fire Risk	B
183	Reduce risk contribution from fires originating in zone CV-3, causing failure of component cooling water (thermal barrier cooling) and service water with subsequent failure of reactor coolant pump seal injection.	Elimination or improved mitigation of fires in this area.	Fire Risk	B
184	Reduce risk contribution from fires in EDG building, fire initiator DG1L1A.	Elimination or improved mitigation of fires in this area.	Fire Risk	D
185	Reduce risk contribution from fires in EDG building, fire initiator DG2L1A.	Elimination or improved mitigation of fires in this area.	Fire Risk	D
186	Increase seismic ruggedness of the ERF Substation batteries. This refers only to the battery racks, not the entire structure.	Increased reliability of the ERF diesel following seismic events	Seismic Risk	F
187	Reduce risk contribution from internal flooding in cable vault area, CV-2 735', by reducing the frequency of the event or by improvements in mitigation of the resulting flooding.	Eliminate or mitigate the consequences of a flood in this area.	Internal Flooding	D

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
188	Reduce risk contribution from internal flooding in Safeguards building, N&S. (Source of flooding is a RWST line.	Eliminate or mitigate the consequences of a flood in this area.	Internal Flooding	D
189	Install Westinghouse RCP Shutdown seals to work with high temperature O-Rings.	Reduced seal LOCA probability	Cooling Water	F
190	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	Containment	E

Note 1: The source references are:

1 NEI 05-01 (Reference 24)
A IPE (Reference 4)
B IPEEE (Reference 5
C Beaver Valley Power Station ELT 2004 Strategic Action Plan - Safe Plant Operations (Reference 39)
D BV2REV4 PRA results (Reference 27)
E NISYS-1092-C006 (Reference 37)
F Undocumented conversations/interviews with site personnel.

6 PHASE I ANALYSIS

A preliminary screening of the complete list of SAMA candidates was performed to limit the number of SAMAs for which detailed analysis in Phase II was necessary. The screening criteria used in the Phase I analysis are described below.

- ***Screening Criterion A - Not Applicable***: If a SAMA candidate did not apply to the Beaver Valley Unit 2 plant design, it was not retained.
- ***Screening Criterion B - Already Implemented or Intent Met***: If a SAMA candidate had already been implemented at the Beaver Valley Unit 2 or the intent of the candidate is met, it was not retained.
- ***Screening Criterion C - Combined***: If a SAMA candidate was similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or plant-specific SAMA candidate, only the combined SAMA candidate was retained.
- ***Screening Criterion D - Excessive Implementation Cost***: If a SAMA required extensive changes that will obviously exceed the maximum benefit (Section 4.5), even without an implementation cost estimate, it was not retained.
- ***Screening Criterion E - Very Low Benefit***: If a SAMA from an industry document was related to a non-risk significant system for which change in reliability is known to have negligible impact on the risk profile, it was not retained. (No SAMAs were screened using this criterion.)

Table 6-1 presents the list of Phase I SAMA candidates and provides the disposition of each candidate along with the applicable screening criterion associated with each candidate. Those candidates that have not been screened by application of these criteria are evaluated further in the Phase II analysis (Section 7). It can be seen from this table that 134 SAMAs were screened from the analysis during Phase 1 and that 56 SAMAs passed into the next phase of the analysis.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
15	Install tornado protection on gas turbine generator.	Increased availability of on-site AC power.	Yes	A - Not Applicable	Not applicable. Plant does not have gas turbine generator.
27	Revise procedure to allow operators to inhibit automatic vessel depressurization in non-ATWS scenarios.	Extended HPCI and RCIC operation.	Yes	A - Not Applicable	Not applicable. Description of HPCI and RCIC use implies BWR item.
35	Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	Extended reactor water storage tank capacity.	Yes	A - Not Applicable	Per Expert Panel: LHI only used in LBLOCA sequences, throttling not considered. Long-term cooling is sump recirc.
38	Change the in-containment reactor water storage tank suction from four check valves to two check and two air-operated valves.	Reduced common mode failure of injection paths.	Yes	A - Not Applicable	Not Applicable. Beaver Valley suction of different design.
52	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	Reduced effect of loss of component cooling water by providing a means to maintain the charging pump seal injection following a loss of normal cooling water.	Yes	A - Not Applicable	Charging pump seals do not require cooling.
57	Use existing hydro test pump for reactor coolant pump seal injection.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	Yes	A - Not Applicable	Cannot be implemented due to design limitations using existing pump. The pressure pulses from the positive displacement pump will damage the seal, leading to seal failure
62	Implement procedures to stagger high pressure safety injection pump use after a loss of service water.	Extended high pressure injection prior to overheating following a loss of service water.	Yes	A - Not Applicable	Due to the estimated time of 12 minutes for pump failure following loss of lube oil cooling and the restricted start duty times of 45 minutes between starts, this is not considered a viable option.
63	Use fire prevention system pumps as a backup seal injection and high pressure makeup source.	Reduced frequency of reactor coolant pump seal LOCA.	Yes	A - Not Applicable	Not applicable. Fire pumps do not have sufficient discharge pressure for high pressure makeup source.
69	Install manual isolation valves around auxiliary feedwater turbine-driven steam admission valves.	Reduced dual turbine-driven pump maintenance unavailability.	Yes	A - Not Applicable	Not Applicable. Beaver Valley does not have dual turbine design.
70	Install accumulators for turbine-driven auxiliary feedwater pump flow control valves.	Eliminates the need for local manual action to align nitrogen bottles for control air following a loss of off-site power.	Yes	A - Not Applicable	Not applicable. TDAFW has a mechanical FCV. Steam generator FCV are electro-hydraulic with hand pump backup.
76	Change failure position of condenser makeup valve if the condenser makeup valve fails open on loss of air or power.	Allows greater inventory for the auxiliary feedwater pumps by preventing condensate storage tank flow diversion to the condenser.	Yes	A - Not Applicable	Not applicable. Condenser makeup valve fails closed.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
84	Create ability to switch emergency feedwater room fan power supply to station batteries in a station blackout.	Continued fan operation in a station blackout.	Yes	A - Not Applicable	TDAFW pump rated for high temperature environment. No backup ventilation is needed.
88	Install nitrogen bottles as backup gas supply for safety relief valves.	Extended SRV operation time.	Yes	A - Not Applicable	PORVs are self-actuated, no dependency on air. The pressurizer SRVs and PORVs are self-actuated, no dependency on air. The steam generator ADVs are electro-hydraulic, no dependency on air.
105	Delay containment spray actuation after a large LOCA.	Extended reactor water storage tank availability.	Yes	A - Not Applicable	Delaying the containment spray actuation following a large LOCA, would potentially result in exceeding containment design pressure and/or temperature.
108	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.	Yes	A - Not Applicable	Hydrogen recombiners previously abandoned in-place.
109	Install a passive hydrogen control system.	Reduced hydrogen detonation potential.	Yes	A - Not Applicable	Hydrogen recombiners previously abandoned in-place.
134	Revise procedure to bypass MSIV isolation 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 human error probabilities.	Yes	A - Not Applicable	Expert Panel - Determined this is a BWR issue.
135	Revise procedure to allow override of low pressure core injection during an ATWS event.	Allows immediate control of low pressure core injection. On failure of high pressure core injection and condensate, some plants direct reactor depressurization followed by five minutes of automatic low pressure core injection.	Yes	A - Not Applicable	Not applicable. This should be limited to BWR ATWS response.
139	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	Prevents flood propagation.	Yes	A - Not Applicable	This was not identified as an internal flooding initiator of concern.
140	Increase seismic ruggedness of plant components.	Increased availability of necessary plant equipment during and after seismic events.	Yes	A - Not Applicable	Specific identified items addressed in other SAMAs (see SAMA 186)
141	Provide additional restraints for CO2 tanks.	Increased availability of fire protection given a seismic event.	Yes	A - Not Applicable	Seismic PRA and walkdowns did not identify this as a contributor.
143	Upgrade fire compartment barriers.	Decreased consequences of a fire.	Yes	A - Not Applicable	Individual fires of concern are addressed specifically, see SAMAs 179, 180, 181, 182, 183, 184, 185.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	Yes	A - Not Applicable	Not applicable. Unit 2 design is different than Unit 1.
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	Yes	A - Not Applicable	Not applicable. This item only applicable to Unit 1
182	Reduce risk contribution from fires originating in zone CV-1, causing failure of service water	Elimination or improved mitigation of fires in this area.	Yes	A - Not Applicable	Fires in this area only cause loss of "A" train of service water. Revisions to the PRA model show that fires in this area contribute less that 0,02% of total CDF.
189	Install Westinghouse RCP Shutdown seals to work with high temperature O-Rings.	Reduced seal LOCA probability	Yes	A - Not Applicable	Not applicable. This seal is not available.
7	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.	Yes	B - Intent Met	Intent met. Part of UPS design.
8	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.	Yes	B - Intent Met	Loss of a single 120 VAC bus will induce transient. Procedures and training exist for operator response to loss of vital bus. If loss of two occurs, operators will implement the procedures for loss of both.
9	Provide an additional diesel generator.	Increased availability of on-site emergency AC power.	Yes	B - Intent Met	Intent met though SBO cross-tie to other unit.
10	Revise procedure to allow bypass of diesel generator trips.	Extended diesel generator operation.	Yes	B - Intent Met	Intent met. All non-essential EDG trips are bypassed upon emergency start.
11	Improve 4.16-kV bus cross-tie ability.	Increased availability of on-site AC power.	Yes	B - Intent Met	Intent met. Modifications installed.
12	Create AC power cross-tie capability with other unit (multi-unit site)	Increased availability of on-site AC power.	Yes	B - Intent Met	Intent met. Modifications installed.
16	Improve uninterruptible power supplies.	Increased availability of power supplies supporting front-line equipment.	Yes	B - Intent Met	Intent met. Inverters upgraded.
18	Develop procedures for replenishing diesel fuel oil.	Increased diesel generator availability.	Yes	B - Intent Met	Intent met. Procedure exists.
19	Use fire water system as a backup source for diesel cooling.	Increased diesel generator availability.	Yes	B - Intent Met	Intent met. Procedure exists.
20	Add a new backup source of diesel cooling.	Increased diesel generator availability.	Yes	B - Intent Met	Intent met. Cross-connections and backups available.
21	Develop procedures to repair or replace failed 4 KV breakers.	Increased probability of recovery from failure of breakers that transfer 4.16 kV non-emergency buses from unit station service transformers.	Yes	B - Intent Met	Intent met. Procedure exists.
22	In training, emphasize steps in recovery of off-site power after an SBO.	Reduced human error probability during off-site power recovery.	Yes	B - Intent Met	Intent met. Included in training.
23	Develop a severe weather conditions procedure.	Improved off-site power recovery following external weather-related events.	Yes	B - Intent Met	Intent met. Procedure exists.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
30	Improve ECCS suction strainers.	Enhanced reliability of ECCS suction.	Yes	B - Intent Met	Sump improvements being installed with a phased implementation process IAW GL 2004-02.
31	Add the ability to manually align emergency core cooling system recirculation.	Enhanced reliability of ECCS suction.	Yes	B - Intent Met	Intent met. Automatic with manual backup.
32	Add the ability to automatically align emergency core cooling system to recirculation mode upon refueling water storage tank depletion.	Enhanced reliability of ECCS suction.	Yes	B - Intent Met	Intent met. Automatic with manual backup.
33	Provide hardware and procedure to refill the reactor water storage tank once it reaches a specified low level.	Extended reactor water storage tank capacity in the event of a steam generator tube rupture.	Yes	B - Intent Met	Intent met. Procedure exists.
36	Emphasize timely recirculation alignment in operator training.	Reduced human error probability associated with recirculation failure.	Yes	B - Intent Met	Intent met. Included in training.
40	Provide capability for remote, manual operation of secondary side pilot-operated relief valves in a station blackout.	Improved chance of successful operation during station blackout events in which high area temperatures may be encountered (no ventilation to main steam areas).	Yes	B - Intent Met	Intent met. Valves can be operated locally using hydraulic actuator.
42	Make procedure changes for reactor coolant system depressurization.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	Yes	B - Intent Met	Intent met. Procedure exists.
43	Add redundant DC control power for SW pumps.	Increased availability of SW.	Yes	B - Intent Met	Swing Pump fulfills this function. Standby Service Water Pumps can be aligned to either header.
44	Replace ECCS pump motors with air-cooled motors.	Elimination of ECCS dependency on component cooling system.	Yes	B - Intent Met	Intent met. ECCS pump motors are air cooled.
45	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.	Yes	B - Intent Met	Intent met. Procedure exists.
46	Add a service water pump.	Increased availability of cooling water.	Yes	B - Intent Met	Intent met. The alternate intake facility fulfills this function. An installed spare service water pump that can be aligned to either bus on either loop. Standby service water pumps auto-start on low header pressure.
47	Enhance the screen wash system.	Reduced potential for loss of SW due to clogging of screens.	Yes	B - Intent Met	Intent met. Alternate Intake Facility. Alternate intake facility provides redundancy, there is a PM and monitoring program in place for the screens and screen wash system.
48	Cap downstream piping of normally closed component cooling water drain and vent valves.	Reduced frequency of loss of component cooling water initiating events, some of which can be attributed to catastrophic failure of one of the many single isolation valves.	Yes	B - Intent Met	Intent met. Vents and Drains are capped.
49	Enhance loss of component cooling water (or loss of service water) procedures to facilitate stopping the reactor coolant pumps.	Reduced potential for reactor coolant pump seal damage due to pump bearing failure.	Yes	B - Intent Met	Intent met. Procedure exists.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
50	Enhance loss of component cooling water procedure to underscore the desirability of cooling down the reactor coolant system prior to seal LOCA.	Reduced probability of reactor coolant pump seal failure.	Yes	B - Intent Met	Intent met. Procedure exists.
51	Additional training on loss of component cooling water.	Improved success of operator actions after a loss of component cooling water.	Yes	B - Intent Met	Intent met. Loss of component cooling water included in training program.
53	On loss of essential raw cooling water, proceduralize shedding component cooling water loads to extend the component cooling water heat-up time.	Increased time before loss of component cooling water (and reactor coolant pump seal failure) during loss of essential raw cooling water sequences.	Yes	B - Intent Met	Intent met. Procedure exists.
58	Install improved reactor coolant pump seals.	Reduced likelihood of reactor coolant pump seal LOCA.	Yes	B - Intent Met	Intent met. New design RCP seals installed. See also SAMAs 158 & 189
59	Install an additional component cooling water pump.	Reduced likelihood of loss of component cooling water leading to a reactor coolant pump seal LOCA.	Yes	B - Intent Met	Installed spare pump.
60	Prevent makeup pump flow diversion through the relief valves.	Reduced frequency of loss of reactor coolant pump seal cooling if spurious high pressure injection relief valve opening creates a flow diversion large enough to prevent reactor coolant pump seal injection.	Yes	B - Intent Met	There are relief valves on the charging system piping for the purpose of thermal pressure buildup following containment isolation. The relief valves set points are above the shutoff head of the charging pumps and would not be expected to lift.
61	Change procedures to isolate reactor coolant pump seal return flow on loss of component cooling water, and provide (or enhance) guidance on loss of injection during seal LOCA.	Reduced frequency of core damage due to loss of seal cooling.	Yes	B - Intent Met	Intent met. Procedure exists.
66	Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	Increased availability of feedwater.	Yes	B - Intent Met	Intent met. AFW has backup from service water.
67	Install an independent diesel for the condensate storage tank makeup pumps.	Extended inventory in CST during an SBO.	Yes	B - Intent Met	Have procedure to makeup from PPDWST. Also have ability to gravity feed from DWST to PPDWST. Procedure being developed.
68	Add a motor-driven feedwater pump.	Increased availability of feedwater.	Yes	B - Intent Met	Intent met. Unit has a motor driven startup feedwater pump with suction from the main condenser. Main feedwater pumps are motor driven.
71	Install a new condensate storage tank (auxiliary feedwater storage tank).	Increased availability of the auxiliary feedwater system.	Yes	B - Intent Met	Demin water storage tank is available to refill the PPDWST.
72	Modify the turbine-driven auxiliary feedwater pump to be self-cooled.	Improved success probability during a station blackout.	Yes	B - Intent Met	Intent met. TDAFW is self cooled.
73	Proceduralize local manual operation of auxiliary feedwater system when control power is lost.	Extended auxiliary feedwater availability during a station blackout. Also provides a success path should auxiliary feedwater control power be lost in non-station blackout sequences.	Yes	B - Intent Met	Intent met. Procedure exists.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
75	Use fire water system as a backup for steam generator inventory.	Increased availability of steam generator water supply.	Yes	B - Intent Met	Intent met. Service Water and River Water systems can be used as backup water source for AFW.
79	Replace existing pilot-operated relief valves with larger ones, such that only one is required for successful feed and bleed.	Increased probability of successful feed and bleed.	Yes	B - Intent Met	Beaver Valley has three PORVs, only one is required for successful feed and bleed.
80	Provide a redundant train or means of ventilation.	Increased availability of components dependent on room cooling.	Yes	B - Intent Met	EDG building HVAC is the only identified applicable HVAC system. Portable fans are available as backup.
81	Add a diesel building high temperature alarm or redundant louver and thermostat.	Improved diagnosis of a loss of diesel building HVAC.	Yes	B - Intent Met	High temperature alarm exists. Actions on high temperature include opening doors.
82	Stage backup fans in switchgear rooms.	Increased availability of ventilation in the event of a loss of switchgear ventilation.	Yes	B - Intent Met	Intent met. Fans are not staged in switchgear room, but are nearby.
83	Add a switchgear room high temperature alarm.	Improved diagnosis of a loss of switchgear HVAC.	Yes	B - Intent Met	No high temperature alarm, but multiple alarms for fan trips. Backup fans are available and a procedure exists for implementing temporary ventilation. Analysis shows long time available to implement temporary ventilation. Operators are trained on the procedure for temporary ventilation.
85	Provide cross-unit connection of uninterruptible compressed air supply.	Increased ability to vent containment using the hardened vent.	Yes	B - Intent Met	Have a third train of station air installed that is supplied from a diesel air compressor.
86	Modify procedure to provide ability to align diesel power to more air compressors.	Increased availability of instrument air after a LOOP.	Yes	B - Intent Met	Intent met. Third train of station air installed that is supplied from a diesel air compressor.
87	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 service water cooling.	Yes	B - Intent Met	Have an installed third train of station air supplied by a diesel air compressor.
92	Use the fire water system as a backup source for the containment spray system.	Improved containment spray capability.	Yes	B - Intent Met	Intent met. Procedure exists.
93	Install an unfiltered, hardened containment vent.	Increased decay heat removal capability for non-ATWS events, without scrubbing released fission products.	Yes	B - Intent Met	SAMG guidance contains guidance for a number of containment venting paths. Although not a dedicated hardened vent, redundant and separate venting paths exist.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
95	Enhance fire protection system and standby gas treatment system hardware and procedures.	Improved fission product scrubbing in severe accidents.	Yes	B - Intent Met	Intent met. In SAMG.
103	Institute simulator training for severe accident scenarios.	Improved arrest of core melt progress and prevention of containment failure.	Yes	B - Intent Met	Intent met. Included in training program.
106	Install automatic containment spray pump header throttle valves.	Extended time over which water remains in the reactor water storage tank, when full containment spray flow is not needed.	Yes	B - Intent Met	Implemented IAW EOPs.
114	Install self-actuating containment isolation valves.	Reduced frequency of isolation failure.	Yes	B - Intent Met	Intent met. AOV, MOV and CV containment isolation valves; those that are required to close are AOVs and fail closed on loss-of-air, or are administratively controlled closed, except CCP to RCP seal cooling.
115	Locate residual heat removal (RHR) inside containment	Reduced frequency of ISLOCA outside containment.	Yes	B - Intent Met	Intent met. RHS pumps are located inside containment.
116	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.	Yes	B - Intent Met	Break flow is expected to submerge the break location; in addition, the fission product releases would pass through building ventilation which is filtered through the supplemental leak collection and release system.
117	Revise EOPs to improve ISLOCA identification.	Increased likelihood that LOCAs outside containment are identified as such. A plant had a scenario in which an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment.	Yes	B - Intent Met	Intent met. EOPs provide guidance to eliminate other routes.
123	Proceduralize use of pressurizer vent valves during steam generator tube rupture sequences.	Backup method to using pressurizer sprays to reduce primary system pressure following a steam generator tube rupture.	Yes	B - Intent Met	Intent met. Procedure exists.
124	Provide improved instrumentation to detect steam generator tube ruptures, such as Nitrogen-16 monitors).	Improved mitigation of steam generator tube ruptures.	Yes	B - Intent Met	Intent met. N-16 monitors installed.
127	Revise emergency operating procedures to direct isolation of a faulted steam generator.	Reduced consequences of a steam generator tube rupture.	Yes	B - Intent Met	Intent met by alternate means. Procedure EOP E-2 directs operators to isolate faulted SGs by closing all actuated or manual valves associated with the affected SG. SAMA 164 will enhance procedures to provide steps to isolate any stuck-open safety valves on a ruptured SG.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
128	Direct steam generator flooding after a steam generator tube rupture, prior to core damage.	Improved scrubbing of steam generator tube rupture releases.	Yes	B - Intent Met	Intent met by alternate means. Procedure EOP E-3 directs operators to feed ruptured SGs if the narrow range level is below 12%. SAMA 164, will enhance procedures to provide steps to; consider feeding a faulted-ruptured SG to provide continuous scrubbing (by maintaining ~12% to 50% narrow range SG level by throttling AFW flow to the ruptured SG), isolate any stuck-open safety valves on a ruptured SG, or close the RCS Loop Stop Valves on the ruptured SG to terminate or minimize the release.
132	Provide an additional control system for rod insertion (e.g., AMSAC).	Improved redundancy and reduced ATWS frequency.	Yes	B - Intent Met	Intent met. AMSAC installed.
138	Improve inspection of rubber expansion joints on main condenser.	Reduced frequency of internal flooding due to failure of circulating water system expansion joints.	Yes	B - Intent Met	Implemented - Program exists to inspect and replace expansion joints in the turbine building.
142	Replace mercury switches in fire protection system.	Decreased probability of spurious fire suppression system actuation.	Yes	B - Intent Met	Intent met. Remaining mercury switches will not cause spurious suppression system actuations affecting plant equipment.
144	Install additional transfer and isolation switches.	Reduced number of spurious actuations during a fire.	Yes	B - Intent Met	Current fire protection safe shutdown procedures intentionally de-energize circuits to reduce the number of spurious actuations.
145	Enhance fire brigade awareness.	Decreased consequences of a fire.	Yes	B - Intent Met	Fire brigade training and procedures meet current industry practices.
146	Enhance control of combustibles and ignition sources.	Decreased fire frequency and consequences.	Yes	B - Intent Met	Intent met. Procedure exists.
148	Enhance procedures to mitigate large break LOCA.	Reduced consequences of a large break LOCA.	Yes	B - Intent Met	Intent met. Owner's Group recommendations implemented.
149	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.	Yes	B - Intent Met	Safety Parameter Display System installed.
150	Improve maintenance procedures.	Improved prevention of core melt sequences by increasing reliability of important equipment.	Yes	B - Intent Met	Intent met. Maintenance procedures are written IAW current industry standards and guidance.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
151	Increase training and operating experience feedback to improve operator response.	Improved likelihood of success of operator actions taken in response to abnormal conditions.	Yes	B - Intent Met	Training and operating experience feedback meets current industry standards and practices.
152	Develop procedures for transportation and nearby facility accidents.	Reduced consequences of transportation and nearby facility accidents.	Yes	B - Intent Met	Intent met but will be reevaluated (nearby industrial facilities) because the potential for impacts of the expanded propane storage facility being modified across the river from BV.
154	Provide Beaver Valley Units 1 and 2 with 4,160 V Bus Crosstie Capability	Adds a success path for blackout on Unit 2 when both Unit 1 diesel generators work, and vice versa	Yes	B - Intent Met	See SAMA #9
156	Operate plant with all PORV block valves open or provide procedures to open block valves when Main Feedwater is lost.	Increased pressure relief capacity to prevent reactor vessel rupture during ATWS.	Yes	B - Intent Met	Intent met. Normal operational alignment has all 3 block valves open. The configuration risk management program limits the amount of time the PORV block valves can remain closed..
157	Loss of Emergency Switchgear Room HVAC , Enhanced Loss of HVAC Procedures	Confidence that operators will prevent thermal damage to switchgear	Yes	B - Intent Met	Intent met. Procedure exists, temporary equipment staged.
158	RCP Seal Cooling for Station Blackout, Potential modifications under review	Reduced frequency of RCP seal LOCA resulting from blackout	Yes	B - Intent Met	Intent met. High temperature seals installed.
160	Pressurizer PORV sticking open after loss of offsite power, Eliminate challenge by defeating the 100% load rejection capability	Reduced frequency of pressurizer PORV sticking open	Yes	B - Intent Met	Turbine trip above 49% power results in a direct reactor trip.
161	Fast 4,160 V Bus Transfer Failure, Explicit Procedure and Training on breaker repair or change out	Reduced frequency that breaker failures will challenge diesel generators	Yes	B - Intent Met	Intent met - Existing procedures implement replacement. Spare breaker internals are available near the required locations.
163	Modify Loss of DC AOP to proceduralize the use of backup battery chargers.	Provide better reliability of the DC busses.	Yes	B - Intent Met	Procedures implemented.
1	Provide additional DC battery capacity.	Extended DC power availability during an SBO.	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.
2	Replace lead-acid batteries with fuel cells.	Extended DC power availability during an SBO.	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.
4	Improve DC bus load shedding.	Extended DC power availability during an SBO.	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.
5	Provide DC bus cross-ties.	Improved availability of DC power system.	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
6	Provide additional DC power to the 120/240V vital AC system.	Increased availability of the 120 V vital AC bus.	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.
74	Provide hookup for portable generators to power the turbine-driven auxiliary feedwater pump after station batteries are depleted.	Extended auxiliary feedwater availability.	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.
159	Battery Capacity for steam generator level instruments for station blackout, Enhance procedures on shedding loads or using portable battery chargers. One train of the battery chargers will be powered from the site operable emergency diesel generator once the Station Blackout Unit crosstie modification is complete.	Extended operating time for steam generator level instruments for less of all AC power scenarios	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.
162	Provide a dedicated diesel driven feed water pump with supply tank to provide an additional source of water for SG tube coverage during SGTR events.	This would eliminate the LERF category and reduce all SGTR events to Small Early Releases.	Yes	C - Combined	Combined with SAMA 78 for installation of dedicated AFW system.
166	Provide additional emergency 125V DC battery capability.	Better coping for long term station blackouts	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.
24	Bury off-site power lines.	Improved off-site power reliability during severe weather.	Yes	D - Excess Cost	Excessive Implementation Cost
34	Provide an in-containment reactor water storage tank.	Continuous source of water to the safety injection pumps during a LOCA event, since water released from a breach of the primary system collects in the in-containment reactor water storage tank, and thereby eliminates the need to realign the safety injection pumps for long-term post-LOCA recirculation.	Yes	D - Excess Cost	Excessive Implementation Cost
77	Provide a passive, secondary-side heat-rejection loop consisting of a condenser and heat sink.	Reduced potential for core damage due to loss-of-feedwater events.	Yes	D - Excess Cost	Excessive Implementation Cost
90	Create a reactor cavity flooding system.	Enhanced debris cool ability, reduced core concrete interaction, and increased fission product scrubbing.	Yes	D - Excess Cost	Excessive Implementation Cost
91	Install a passive containment spray system.	Improved containment spray capability.	Yes	D - Excess Cost	Excessive Implementation Cost
97	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 basemat.	Yes	D - Excess Cost	Excessive Implementation Cost
98	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.	Yes	D - Excess Cost	Excessive Implementation Cost
99	Strengthen primary/secondary containment (e.g., add ribbing to containment shell).	Reduced probability of containment over-pressurization.	Yes	D - Excess Cost	Expert Panel - >MAB
100	Increase depth of the concrete base mat or use an alternate concrete material to ensure melt-through does not occur.	Reduced probability of basemat melt-through.	Yes	D - Excess Cost	Excessive Implementation Cost

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
101	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.	Yes	D - Excess Cost	Excessive Implementation Cost
102	Construct a building to be connected to primary/secondary containment and maintained at a vacuum.	Reduced probability of containment over-pressurization.	Yes	D - Excess Cost	Excessive Implementation Cost
110	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.	Yes	D - Excess Cost	Excessive Implementation Cost
120	Replace steam generators with a new design.	Reduced frequency of steam generator tube ruptures.	Yes	D - Excess Cost	The cosst to replace the steam generators solely for this SAMA is cost-excessive.
121	Increase the pressure capacity of the secondary side so that a steam generator tube rupture would not cause the relief valves to lift.	Eliminates release pathway to the environment following a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
122	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture	Enhanced depressurization capabilities during steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
125	Route the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove most of the fission products.	Reduced consequences of a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
126	Install a highly reliable (closed loop) steam generator shell-side heat removal system that relies on natural circulation and stored water sources	Reduced consequences of a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
129	Vent main steam safety valves in containment.	Reduced consequences of a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
147	Install digital large break LOCA protection system.	Reduced probability of a large break LOCA (a leak before break).	Yes	D - Excess Cost	Excessive Implementation Cost
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	No		Installed spare battery chargers. Retain for Phase II analysis for evaluation of portable generator.
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	No		Retain for Phase II analysis.
14	Install a gas turbine generator.	Increased availability of on-site AC power.	No		Retain for Phase II analysis. ERF diesel generator can supply minimal loads
17	Create a cross-tie for diesel fuel oil (multi-unit site).	Increased diesel generator availability.	No		Retain for Phase II analysis.
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	No		Retain for Phase II analysis.
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	No		Retain for Phase II analysis.
28	Add a diverse low pressure injection system.	Improved injection capability.	No		Retain for Phase II analysis.
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	No		Retain for Phase II analysis.
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injection systems.	No		Retain for Phase II analysis.
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	No		Retain for Phase II analysis.
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	No		Retain for Phase II analysis.
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	No		Retain for Phase II analysis.
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	No		Retain for Phase II analysis.
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	No		Retain for Phase II analysis.
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	No		Retain for Phase II analysis. Digital feedwater not installed and not planned.
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	No		Retain for Phase II analysis.
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	No		Retain for Phase II analysis.
94	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.	No		SAMG guidance contains guidance for a number of containment venting paths. Some of these vent paths are filtered. Retain for Phase II analysis.
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	No		Retain for Phase II analysis.
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	No		Retain for Phase II analysis.
107	Install a redundant containment spray system.	Increased containment heat removal ability.	No		Retain for Phase II analysis.
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	No		Retain for Phase II analysis.
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	No		Retain for Phase II analysis.
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	No		Retain for Phase II analysis.
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	No		Retain for Phase II analysis.
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	No		Retain for Phase II analysis.
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	No		Retain for Phase II analysis.
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	No		Retain for Phase II analysis.
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	No		Retain for Phase II analysis.
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	No		Capability exists outside the control room, but analysis shows the action cannot be taken in the time required. Retain for Phase II analysis.
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	No		Retain for Phase II analysis.
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	No		Analysis showed that sufficient time is not available to perform this action. PRA updates reduced the importance of this item as a vulnerability. Retain for Phase II analysis.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	No		Retain for Phase II analysis.
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	No		Retain for Phase II analysis.
169	Improve operator performance. Operator fails to align makeup to RWST - SGTR, secondary leak	Top 10 operator actions OPRWM1	No		Retain for Phase II analysis.
170	Improve operator performance. Operator fails to manually trip reactor - ATWS	Top 10 operator actions OPROT1	No		Retain for Phase II analysis.
171	Improve operator performance. Operator fails to realign main feedwater - no SI signal	Top 10 operator actions OPROF2	No		Retain for Phase II analysis.
172	Improve operator performance. Operator fails to initiate AFW following transient	Top 10 operator actions OPROS6	No		Retain for Phase II analysis.
173	Improve operator performance. Operator aligns spare battery charger 2-9 to 2-2	Top 10 operator actions OPRDC2	No		Retain for Phase II analysis.
174	Improve operator performance. Operator aligns spare battery charger 2-7 to 2-1	Top 10 operator actions OPRDC1	No		Retain for Phase II analysis.
175	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB2	No		Retain for Phase II analysis.
176	Improve operator performance. Operator fails to trip RCP during loss of CCP	Top 10 operator actions OPROC1	No		Retain for Phase II analysis.
177	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB1	No		Retain for Phase II analysis.
178	Improve operator performance. Operator fails to identify ruptured SG or initiate isolation	Top 10 operator actions OPRSL1	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
179	Reduce risk contribution from fires originating in Zone CB-3, causing a total loss of main feedwater and auxiliary feedwater with subsequent failure of feed and bleed.	Elimination or improved mitigation of fires in this area.	No		Retain for Phase II analysis.
180	Reduce risk contribution from fires originating in zone CT-1, causing a total loss of service water.	Elimination or improved mitigation of fires in this area.	No		Retain for Phase II analysis.
181	Reduce risk contribution from fires originating in zone SB-4, causing a total loss of normal AC power with subsequent failure of emergency AC power and station crosstie leading to station blackout.	Elimination or improved mitigation of fires in this area.	No		Retain for Phase II analysis.
183	Reduce risk contribution from fires originating in zone CV-3, causing failure of component cooling water (thermal barrier cooling) and service water with subsequent failure of reactor coolant pump seal injection.	Elimination or improved mitigation of fires in this area.	No		Retain for Phase II analysis.
184	Reduce risk contribution from fires in EDG building, fire initiator DG1L1A.	Elimination or improved mitigation of fires in this area.	No		Retain for Phase II analysis.
185	Reduce risk contribution from fires in EDG building, fire initiator DG2L1A.	Elimination or improved mitigation of fires in this area.	No		Retain for Phase II analysis.
186	Increase seismic ruggedness of the ERF Substation batteries. This refers only to the battery racks, not the entire structure.	Increased reliability of the ERF diesel following seismic events	No		Retain for Phase II analysis.
187	Reduce risk contribution from internal flooding in cable vault area, CV-2 735', by reducing the frequency of the event or by improvements in mitigation of the resulting flooding.	Eliminate or mitigate the consequences of a flood in this area.	No		Retain for Phase II analysis.
188	Reduce risk contribution from internal flooding in Safeguards building, N&S. (Source of flooding is a RWST line.	Eliminate or mitigate the consequences of a flood in this area.	No		Retain for Phase II analysis.
190	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	No		Retain for Phase II analysis.

7 PHASE II SAMA ANALYSIS

A cost-benefit analysis was performed on each of the SAMA candidates remaining after the Phase I screening. The benefit of a SAMA candidate is the difference between the baseline cost of severe accident risk (maximum benefit from Section 4.5) and the cost of severe accident risk with the SAMA implemented (Section 7.1). The cost figure used is the estimated cost to implement the specific SAMA. If the estimated cost of implementation exceeds the benefit of implementation, the SAMA is not cost-beneficial.

Since the SAMA analysis is being performed separately for each Beaver Valley unit, the costs and the benefits are provided on a per-unit basis. If a SAMA candidate is shared by the units, that information is noted in the Phase II SAMA candidate list and it is analyzed in a manner consistent with its applicability to both units.

7.1 SAMA BENEFIT

7.1.1 Severe Accident Risk with SAMA Implemented

Bounding analyses were used to determine the change in risk following implementation of SAMA candidates or groups of similar SAMA candidates. For each analysis case, the Level 1 internal events or Level 2 PRA models were altered to conservatively consider implementation of the SAMA candidate(s). Then, severe accident risk measures were calculated using the same procedure used for the baseline case described in Section 3. The changes made to the PRA models for each analysis case are described in Appendix A.

A "bounding analyses" are exemplified by the following:
LBLOCA
This analysis case was used to evaluate the change in plant risk profile that would be achieved if a digital large break LOCA protection system was installed. Although the proposed change would not completely eliminate the potential for a large break LOCA, a bounding benefit was estimated by removing the large break LOCA initiating event. This analysis case was used to model the benefit of SAMA xx.

DCPWR
This analysis case was used to evaluate plant modifications that would increase the availability of Class 1E DC power (e.g., increased battery capacity or the installation of a diesel-powered generator that would effectively increase battery capacity). Although the proposed SAMAs would not completely eliminate the potential failure, a bounding benefit was estimated by removing the

battery discharge events and battery failure events. This analysis case was used to model the benefit of SAMAs a, b, etc.

The severe accident risk measures were obtained for each analysis case by modifying the baseline model in a simple manner to capture the effect of implementation of the SAMA in a bounding manner. Bounding analyses are very conservative and result in overestimation of the benefit of the candidate analyzed. However, if this bounding assessment yields a benefit that is smaller than the cost of implementation, then is it obvious that the effort involved in refining the PRA modeling approach for the SAMA would be unnecessary because it would only yield a lower benefit result. If the benefit is greater than the cost when modeled in this bounding approach, it is necessary to refine the PRA model of the SAMA to remove conservatism. As a result of this modeling approach, models representing the Phase II SAMAs will not all be at the same level of detail and if any are implemented, the PRA result after implementation of the final installed design will differ from the screening-type analyses done during this evaluation.

7.1.2 Cost of Severe Accident Risk with SAMA Implemented

Using the risk measures determined as described in Section 7.1.1, severe accident impacts in four areas (offsite exposure cost, off-site economic cost, on-site exposure cost, and on-site economic cost) were calculated using the same procedure used for the baseline case described in Section 4. As in Section 4.5, the severe accident impacts were summed to estimate the total cost of severe accident risk with the SAMA implemented.

7.1.3 SAMA Benefit Calculation

The respective SAMA benefit was calculated by subtracting the total cost of severe accident risk with the SAMA implemented from the baseline cost of severe accident risk (maximum benefit from Section 4.5). The estimated benefit for each SAMA candidate is listed in Table 7.1. The calculation of the benefit is performed using an Excel spreadsheet.

7.2 COST OF SAMA IMPLEMENTATION

The final step in the evaluation of the SAMAs is estimating the cost of implementation for comparison with the benefit. For the purpose of this analysis the BVNP staff has estimated that the cost of making a change to a procedure and for conducting the necessary training on a procedure change is expected to exceed **$15,000**. Similarly, the minimum cost associated with development and implementation of an integrated hardware modification package (including post-implementation costs, e.g. training) was assumed to be **$100,000**. These values were used for comparison with the benefit of SAMAs.

The benefits resulting from the bounding estimates presented in the benefit analysis are in some cases rather low. In those cases for which the benefits are so low that it is obvious that the implementation costs would exceed the benefit, a detailed cost estimate was not warranted. Plant staff judgment is applied in assessing whether the benefit approaches the expected implementation costs in many cases

Plant staff judgment was obtained from an independent, expert panel consisting of senior staff members from the PRA group, the design group, operations and license renewal. This panel reviewed the benefit calculation results and, based upon their experience with developing and implementing modifications at the plant, judged whether a modification could be made to the plant that would be cost beneficial in comparison with the calculated benefit. The purpose of this approach was to minimize the effort expended on detailed cost estimation. The cost estimations provided by the expert panel are included in Table 7-1 along with the conclusions reached for each SAMA evaluated for cost/benefit.

It should be noted that the results of the sensitivities of Section 8 influenced the decisions of whether a SAMA was considered to be potentially cost beneficial. If the benefits calculated in the sensitivity analyses exceeded the estimated cost of the SAMA, it was considered potentially cost beneficial.

7.3 SAMAs WITH SHARED BENEFIT OR COSTS

A number of SAMAs either benefit both BVPS-1 and BVPS-2 or the cost of implementation would be shared by both units. In this case, consideration of the costs and benefits at only one unit is not appropriate.

SAMA 14, installation of a gas turbine generator, would provide benefit for both units. The maximum combined benefit for this SAMA is $ 1.9 million ($1,495K in Unit 2 and $400K in Unit 1). The cost to implement this SAMA is greater than $7 million. Even with the combined benefit, this SAMA is not cost beneficial.

SAMA 186 (Unit 2) and 187 (Unit 1), increase the seismic ruggedness of the ERF Substation batteries, would provide benefit for both units. Currently the ERF diesel generator can provide power to the Unit 1 Dedicated AFW system, but very little equipment on Unit 2. The benefit of this SAMA to Unit 2 is $3.8K compared to the Unit 1 benefit of $525K. The estimated cost for implementing this SAMA is $300K. This SAMA is considered potentially cost beneficial for BVPS-1, but not for BVPS-2.

SAMA 190 (Unit 2) and 186 (Unit 1) provide a containment cross-tie between the units, would provide benefit to both units. However, the result of using this cross-tie to mitigate an event would result in contamination of both units. The cost of cleanup of the opposite unit is not included in the benefit calculation. Due to the high cost of implementation and the impact on the opposite unit, this SAMA is not considered cost beneficial for either unit.

Unit 1 SAMA 188 (RWST cross-tie) would provide a benefit for both units. However, since the Unit 2 RWST is significantly larger than the Unit 1 RWST, the benefit to Unit 2 would be small and was therefore not considered as a SAMA. The high cost of implementation (>$4,000K), therefore, makes this SAMA not cost beneficial (at either unit).

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	35.42%	29.91%	DC01	Case assumes no failure or depletion of DC power system.	$1,544K	$120K	Expert Panel	Potentially Cost-Beneficial	Potentially cost Beneficial. TDAFW does not require DC power to continue running. This item is to provide portable generator to supply SG level indication.
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	10.83%	9.96%	NOLOSP	This case was used to determine the benefit of eliminating all loss of offsite power events, both as the initiating event and subsequent to a different initiating event. This allows evaluation of various possible improvements that could reduce the risk associated with loss of offsite power events. For the purposes of the analysis, a single bounding analysis was performed which assumed that loss of offsite power events do not occur, both as an initiating event and subsequent to a different initiating event.	$519K	>$2,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
14	Install a gas turbine generator.	Increased availability of on-site AC power.	35.00%	28.87%	NOSBO	This case is used to determine the benefit of eliminating all Station Blackout events. This allows evaluation of possible improvements related to SBO sequences. For the purpose of the analysis, a single bounding analysis is performed that assumes the Diesel Generators do not fail.	$1,495K	>$7,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 14 in Unit 1. See report section 7.3.	Cost Exceeds benefit.
17	Create a cross-tie for diesel fuel oil (multi-unit site).	Increased diesel generator availability.	0.83%	0.70%	SBO1	This case eliminates the failures of the EDGs due to failures in the fuel oil system.	$36.1K	$500K	Expert Panel	Not Cost-Beneficial	No fuel oil cross-tie exists on Unit 2, neither between the Unit 2 trains nor to Unit 1. Implementation would require a modification since there are no existing valves large enough to provide even temporary connection ability. Cost exceeds benefit.
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	0.83%	0.34%	LOCA02	Assume high pressure injection does not fail, works perfectly.	$22.1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	0.83%	0.34%	LOCA02	Assume high pressure injection does not fail, works perfectly.	$22.1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
28	Add a diverse low pressure injection system.	Improved injection capability.	0.00%	0.03%	LOCA03	Assume low pressure injection system does not fail.	$2.2K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	0.00%	0.03%	LOCA03	Assume low pressure injection system does not fail.	$2.2K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	2.08%	1.57%	LOCA01	Eliminate all small LOCA evens	$83.8K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injection systems.	0.83%	0.34%	LOCA02	Assume high pressure injection does not fail, works perfectly.	$22.1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	2.08%	1.57%	LOCA01	Eliminate all small LOCA evens	$83.8K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	0.00%	0.00%	CHG01	Remove the dependency of the charging pumps on cooling water.	<$1K	>$300K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	31.25%	26.32%	RCPLOCA	This case was used to determine the benefit of eliminating all RCP seal LOCA events. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.	$1,358K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	31.25%	26.32%	RCPLOCA	This case was used to determine the benefit of eliminating all RCP seal LOCA events. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.	$1,358K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	0.00%	0.11%	CCW01	Assume CCW pumps do not failure	$6.0K	$130K	Expert Panel	Not Cost-Beneficial	Hardware modification required as well as procedure changes.
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	0.83%	0.50%	FW01	Eliminate all loss of feedwater initiators.	$27.2K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	42.08%	34.99%	DAFW	Unit 2 baseline model with two additions (1) Dedicated AFW (like U1), and (2) portable DC generator for SG level indication power	$1,810K	$3,000K	Expert Panel	Potentially Cost-Beneficial (because the upper bound sensitivity benefit exceeds the cost)	Cost to purchase pump, installation, piping, procedures, etc. to install a dedicated feedwater system similar to Unit 1 and would provide a significant reduction in CDF.
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	0.00%	0.01%	INSTAIR1	This case was used to determine the benefit of replacing the air compressors. For the purposes of the analysis, a single bounding analysis was performed which assumed the service and instrument air compressors do not fail.	<$1K	>$100K	Expert Panel Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
94	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.	0.00%	53.86%	CONT01	Eliminate all failures of containment due to overpressure.	$2,427K	$9,000K	Industry studies (NUREG 1437 supplements) with inflation	Not Cost-Beneficial	Some venting capability currently exists but the post-accident environment could preclude venting. A different vent was considered necessary to assure continued filtering.
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	0.00%	0.45%	H2BURN	Eliminate all Hydrogen detonation.	$25.8K	>$500K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Hydrogen recombiners previously abandoned in place.
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	0.42%	0.13%	LOCA05	Eliminate all piping failure LOCAs.	$8.5K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Have implemented RI-ISI.
107	Install a redundant containment spray system.	Increased containment heat removal ability.	0.00%	53.86%	CONT01	Eliminate all failures of containment due to overpressure.	$2,427K	>$10,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds the benefit.

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	1.25%	2.43%	LOCA06	Eliminate all ISLOCA events	$135K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	0.00%	0.43%	CONT02	Eliminate all containment isolation failures	$20.1K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	1.25%	2.43%	LOCA06	Eliminate all ISLOCA events	$135K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Increased outage frequency/duration.
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	0.00%	0.01%	LOCA06A	LOCA06 with baseline including optr action to isolate ISLOCA events	<$1K	>$15K	Expert Panel	Not Cost-Beneficial	The PRA case to evaluate the benefit of this SAMA significantly over estimates the benefit. The PRA model does not contain a human error event for failure of the operators to isolate the ISLOCA since the leak pathway contains three check valves, all of which must fail for the ISLOCA to occur. If a human action is credited, the benefit would be extremely small. The results provided are from a sensitivity case comparing the baseline (in which credit is given for break isolation) with the elimination of all ISLOCAs. This is very conservative and still yields extremely small benefits.
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	1.25%	3.02%	NOSGTR	This case was used to determine the benefit of eliminating all SGTR events. This allows evaluation of various possible improvements that could reduce the risk associated with SGTR events. For the purposes of the analysis, a single bounding analysis was performed which assumed that SGTR events do not occur	$165K	>$3,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	0.42%	0.03%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$4.8K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	0.42%	0.03%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$4.8K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	0.42%	0.03%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$4.8K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	0.42%	0.03%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$4.8K	>$100K	Expert Panel Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	0.42%	0.03%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$4.8K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	0.00%	0.03%	NOSLB	This case was used to determine the benefit of installing secondary side guard pipes up to the MSIVs. This would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. For the purposes of the analysis, a single bounding analysis was performed which assumed that no steam line break events occur.	$1.7K	>$100K	Expert Panel Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	0.42%	0.03%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$4.8K	>$100K	Expert Panel Implementation will require plant modification.	Not Cost-Beneficial	Cost exceeds benefit.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	0.83%	1.48%	SGTR4	Operators close the RCS loop stop valves and gag a stuck-open SV	$86.4K	$50K	Expert Panel	Potentially Cost-Beneficial	SAMA is potentially cost beneficial. Loop stop valves are also not design to close against differential pressure and under accident conditions will not fully seat since hoses must be installed to provide pressure between the seats to fully seat the valve.
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	31.25%	26.32%	RCPLOCA	This case was used to determine the benefit of eliminating all RCP seal LOCA events. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.	$1,358K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
169	Improve operator performance. Operator fails to align makeup to RWST - SGTR, secondary leak	Top 10 operator actions OPRWM1	0.00%	0.20%	HEP1	Reduced the probability of basic event OPRWA1 by a factor of 3.	$10.7K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
170	Improve operator performance. Operator fails to manually trip reactor - ATWS	Top 10 operator actions OPROT1	0.00%	0.01%	HEP2	Reduced the probability of basic event OPRWBV3 by a factor of 3.	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
171	Improve operator performance. Operator fails to realign main feedwater - no SI signal	Top 10 operator actions OPROF2	0.00%	0.26%	HEP3	Reduced the probability of basic event OPROS6 by a factor of 3.	$13.6K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
172	Improve operator performance. Operator fails to initiate AFW following transient	Top 10 operator actions OPROS6	0.83%	0.84%	HEP4	Reduced the probability of basic event OPROB2 by a factor of 3.	$42.6K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
173	Improve operator performance. Operator aligns spare battery charger 2-9 to 2-2	Top 10 operator actions OPRDC2	0.00%	0.10%	HEP5	Reduced the probability of basic event OPRWM1 by a factor of 3.	$5.2K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
174	Improve operator performance. Operator aligns spare battery charger 2-7 to 2-1	Top 10 operator actions OPRDC1	0.00%	0.11%	HEP6	Reduced the probability of basic event OPROC1 by a factor of 3.	$5.5K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
175	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB2	1.25%	0.25%	HEP7	Reduced the probability of basic event OPROD2 by a factor of 3.	$20.2K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
176	Improve operator performance. Operator fails to trip RCP during loss of CCP	Top 10 operator actions OPROC1	0.00%	0.12%	HEP8	Reduced the probability of basic event OPROD1 by a factor of 3.	$6.4K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
177	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB1	0.00%	0.02%	HEP9	Reduced the probability of basic event OPRCD6 by a factor of 3.	$1.8K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
178	Improve operator performance. Operator fails to identify ruptured SG or initiate isolation	Top 10 operator actions OPRSL1	0.00%	0.25%	HEP10	Reduced the probability of basic event OPRLR1 by a factor of 3.	$17.6K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
179	Reduce risk contribution from fires originating in Zone CB-3, causing a total loss of main feedwater and auxiliary feedwater with subsequent failure of feed and bleed.	Elimination or improved mitigation of fires in this area.	2.08%	0.44%	FIRE05	This case eliminates the fires in zone CB-3 that cause a total loss of main feedwater and auxiliary feedwater with subsequent failure of bleed and feed.	$34.4K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
180	Reduce risk contribution from fires originating in zone CT-1, causing a total loss of service water.	Elimination or improved mitigation of fires in this area.	4.58%	3.92%	FIRE06	This case eliminates the fires in zone CT-1 that cause a total loss of service water.	$202K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
181	Reduce risk contribution from fires originating in zone SB-4, causing a total loss of normal AC power with subsequent failure of emergency AC power and station crosstie leading to station blackout.	Elimination or improved mitigation of fires in this area.	0.00%	0.21%	FIRE07	This case eliminates the fires in zone SB-4 that cause a total loss of normal AC power with subsequent failure of emergency AC power and station crosstie leading to station blackout.	$10.7K	$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
183	Reduce risk contribution from fires originating in zone CV-3, causing failure of component cooling water (thermal barrier cooling) and service water with subsequent failure of reactor coolant pump seal injection.	Elimination or improved mitigation of fires in this area.	1.25%	1.03%	FIRE09	This case eliminates the fires in zone CV-3 that cause failure of component cooling water (thermal barrier cooling) and service water with subsequent failure of reactor coolant pump seal injection.	$54.6K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
184	Reduce risk contribution from fires in EDG building, fire initiator DG1L1A.	Elimination or improved mitigation of fires in this area.	3.75%	3.18%	FIRE10	This case eliminates the fires in zone DG1L1A, Emergency Diesel Generator (EDG) building.	$164K	$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.. This represents 1/2 the cost; remainder associated with SAMA 185.
185	Reduce risk contribution from fires in EDG building, fire initiator DG2L1A.	Elimination or improved mitigation of fires in this area.	3.75%	3.17%	FIRE11	This case eliminates the fires in zone DG2L1A, EDG building.	$163K	$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. This represents 1/2 the cost; remainder associated with SAMA 184.
186	Increase seismic ruggedness of the ERF Substation batteries. This refers only to the battery racks, not the entire structure.	Increased reliability of the ERF diesel following seismic events	0.00%	0.07%	SEISMIC1	This case assumes a seismic ruggedness for the ERF Substation battery that is the same as that for the station batteries.	$3.8K	$300K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 187 in Unit 1. See report section 7.3.	Unit 1 benefit - Reference U1 SAMA 187

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
187	Reduce risk contribution from internal flooding in cable vault area, CV-2 735', by reducing the frequency of the event or by improvements in mitigation of the resulting flooding.	Eliminate or mitigate the consequences of a flood in this area.	0.00%	0.00%	FLOOD1D	FLOOD1 with the operators failing to isolate the leakage from the fire water pipe	<$1K	>$15K	Expert Panel	Not Cost-Beneficial	Source of flooding is a 4" fire water pipe that traverses the area. The PRA currently does not include credit for the procedure that is in place to isolate a leak/break in the subject piping; i.e., the PRA model does not contain the human error event for failure of the operators to isolate the flood source. If the human action is credited, the benefit for improvements in mitigate would be extremely small. The results provided are from a sensitivity case comparing a revised baseline (in which credit is given for break isolation) (FLOOD1D) with the elimination of this internal flooding scenario. This is very conservative and still yields extremely small benefits; no change in procedures or hardware would be cost-beneficial.
188	Reduce risk contribution from internal flooding in Safeguards building, N&S. (Source of flooding is a RWST line.	Eliminate or mitigate the consequences of a flood in this area.	1.25%	1.23%	FLOOD2	This case eliminates the safeguards building N&S rooms internal flood.	$63.4K	>$200K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
190	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	0.00%	53.86%	CONT01	Eliminate all failures of containment due to overpressure.	$2,427K	>$10,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 186 in Unit 1. See report section 7.3.	Cost will exceed benefit due to cleanup costs and replacement power at opposite unit.

Note 1 – The current plant procedures and training meet current industry standards. The benefit calculation results provided in this table are based upon an arbitrary reduction in HEP of a factor of 3 and are provided solely to demonstrate the sensitivity of the model to change in the HEP. There are no additional specific procedure improvements that could be identified that would affect the result of the HEP calculations to this level of reduction. Therefore, it is expected that the idealistic benefits presented in the table are not achievable with procedure improvements only and would require additional hardware modifications. In all cases the costs of hardware and procedure changes would exceed the idealistic benefits presented in the table. These SAMAs are, therefore, screened as Not Cost Beneficial.

8 SENSITIVITY ANALYSES

The purpose of performing sensitivity analyses is to examine the impact of analysis assumptions on the results of the SAMA evaluation. This section identifies several sensitivities that can be performed during SAMA (Reference 24) and discusses the sensitivity as is applies to Beaver Valley Unit 2 and the impact of the sensitivity on the results of the Phase II SAMA analysis at BVPS-2.

Unless it was otherwise noted, it is assumed in these sensitivity analyses that sufficient margin existed in the maximum benefit estimation that the Phase I screening would not have to be repeated in the sensitivity analyses.

8.1 PLANT MODIFICATIONS

There are no plant modifications that are currently pending that would be expected to impact the results of this SAMA evaluation.

8.2 UNCERTAINTY

Since the inputs to PRA cannot be known with complete certainty, there is possibility that the actual plant risk is greater than the mean values used in the evaluation of the SAMA described in the previous sections. To consider this uncertainty, a sensitivity analysis was performed in which an uncertainty factor was applied to the frequencies calculated by the PRA and the subsequent benefits were calculated based upon the mean risk values multiplied by this uncertainty factor. The uncertainty factor applied is the ratio of the 95^{th} percentile value of the CDF from the PRA uncertainty analysis to the mean value of the CDF. For Unit 2 the 95^{th} percentile value of the CDF is 3.89E-5/yr; therefore, uncertainty factor is 1.62. Table 8-1 provides the benefit results from each of the sensitivities for each of the SAMA cases evaluated.

8.3 PEER REVIEW FACTS/OBSERVATIONS

The model used in this SAMA analysis includes the resolution of the Facts-and-Observations (F&Os) identified during the PRA Peer Review. Therefore, no specific sensitivities were performed related to this issue.

8.4 EVACUATION SPEED

Three evacuation sensitivity cases were performed to determine the impact of evacuation assumptions. One sensitivity case reduced the evacuation speed by a factor of four (0.05 m/sec) and the second increased the speed to 2.24 m/s. The third sensitivity case assumed an increase by a factor of 1.5 in the alarm time, thus delaying the commencement of physical evacuation.

The base evacuation speed was derived in a conservative manner assuming inclement weather and persons without transportation an average evacuation speed of 0.2 m/s was determined. A decrease in the evacuation speed by a factor of four to 0.05 m/s would have the impact of taking over 2 days to evacuate. Runs with an increase to 2.24 m/s (approximately 5 mph) were also performed to assess the slope and relative sensitivity of the dose to evacuation speed.

The third sensitivity case performed was a delay in the alarm time to simulate problems in communication that might be experienced during the night or severe weather. The alarm delay was multiplied by a factor of 1.5 for this case.

The results of the evacuation sensitivity runs indicated that Mean Total Economic Costs are very insensitive to evacuations speeds. Decreasing the evacuation speed had a maximum impact of 10 percent on total dose. Total dose was not sensitive to a delay on the alarm time. The Mean Population Exceeding 0.05 Sv showed some sensitivity to evacuation speed for the late containment failures. The tables below provide a summary of the evacuation sensitivity results.

Table 8.4-1 Evacuation Speed Sensitivity Results

Release Category	Base Note 1	Evacuation Speed				Alarm Delay	
		Slower (0.11 mph	Percent Change	Faster (5 mph)	Percent Change	1.5 x OALARM	Percent Change
Mean L-EFFECTIVE TOT LIF Dose (Sv)							
INTACT	8	8	1	8	-3	8	0
ECF							
VSEQ	50,400	53,700	7	42,700	-15	50,100	-1
SGTR	44,500	47,400	7	40,500	-9	44,700	0
DCH	86,800	88,900	2	81,500	-6	86,800	0
SECF							
SGTR	50,500	55,500	10	29,000	-43	50,500	0
LOCI	35,200	37,200	6	31,700	-10	35,300	0
BV5	43,800	46,400	6	34,600	-21	44,200	1
LATE							
Large	1,530	1,540	1	1,470	-4	1,540	1
Small	20,200	21,400	6	20,200	0	20,300	0
H2 Burn	19,300	19,900	3	18,700	-3	19,400	1
BMMT	7,680	7,850	2	7,670	0	7,680	0
Mean Population Exceeding 0.05 Sv							
INTACT	0	0	0	0	0	0	0
ECF							
VSEQ	143,000	143,000	0	138,000	-3	143,000	0
SGTR	154,000	154,000	0	147,000	-5	154,000	0
DCH	274,000	275,000	0	266,000	-3	274,000	0
SECF							
SGTR	80,200	80,700	1	72,400	-10	80,200	0
LOCI	37,600	38,400	2	28,300	-25	37,400	-1
BV5	86,700	87,200	1	80,100	-8	86,900	0
LATE							
Large	2	27	1,499	2	-8	3	62
Small	7,170	12,900	80	7,150	0	7,240	1
H2 Burn	21,700	24,700	14	18,500	-15	23,000	6
BMMT	2,210	2,730	24	2,200	0	2,240	1
Mean Total Economic Costs ($)							
INTACT	6.400E+03	6.400E+03	0	6.400E+03	0	6.400E+03	0
ECF							
VSEQ	3.530E+10	3.530E+10	0	3.530E+10	0	3.530E+10	0
SGTR	4.280E+10	4.280E+10	0	4.280E+10	0	4.280E+10	0
DCH	4.800E+10	4.800E+10	0	4.800E+10	0	4.800E+10	0
SECF							
SGTR	2.540E+10	2.540E+10	0	2.540E+10	0	2.540E+10	0
LOCI	2.650E+10	2.650E+10	0	2.650E+10	0	2.650E+10	0
BV5	1.130E+10	1.130E+10	0	1.130E+10	0	1.130E+10	0
LATE							
Large	1.180E+08	1.180E+08	0	1.180E+08	0	1.180E+08	0
Small	1.090E+10	1.090E+10	0	1.090E+10	0	1.090E+10	0
H2 Burn	6.670E+09	6.670E+09	0	6.670E+09	0	6.670E+09	0
BMMT	4.380E+09	4.380E+09	0	4.380E+09	0	4.380E+09	0

Note 1 Current Economic data, 2047 population data, and 2001 met data

8.5 REAL DISCOUNT RATE

Calculation of severe accident impacts in the BVPS-2 SAMA analysis was performed using a "real discount rate" of 7% (0.07/year) as recommended in Reference 20. Use of both a 7% and 3% real discount rate in regulatory analysis is specified in Office of Management Budget (OMB) guidance (Reference 25) and in NUREG/BR-0058 (Reference 26). Therefore, a sensitivity analysis was performed using a 3% real discount rate.

In this sensitivity analysis, the real discount rate in the Level 3 PRA model was changed to 3% from 7% and the Phase II analysis was re-performed with the lower interest rate.

The results of this sensitivity analysis are presented in Table 8-1. This sensitivity analysis does not challenge any decisions made regarding the SAMAs.

8.6 ANALYSIS PERIOD

As described in Section 4, calculation of severe accident impacts involves an analysis period term, t_f, which could have been defined as either the period of extended operation (20 years), or the years remaining until the end of facility life (from the time of the SAMA analysis to the end of the period of extended operation) (40 years for Unit 2).

The value used for this term was the period of extended operation (20 years). This sensitivity analysis was performed using the period from the time of the SAMA analysis to the end of the period of extended operation to determine if SAMAs would be potentially cost-beneficial if performed immediately.

In this sensitivity analysis, the analysis period in the calculation of severe accident risk was modified to 40 years and the Phase II analysis was re-performed with the revised analysis period. The cost of additional years of maintenance, surveillance, calibrations, and training were included appropriately in the cost estimates for SAMAs in this Phase II analysis.

The results of this sensitivity analysis are presented in Table 8-1. This sensitivity analysis does not challenge any decisions made regarding the SAMAs.

Table 8-1 BVPS Unit 2 SAMA Sensitivity Evaluation

BV2 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	DC01	$1,544K	$2,227K	$1,378K	$2,009K	$2,966K	$120K	Expert Panel	Potentially Cost-Beneficial	Potentially cost Beneficial. TDAFW does not require DC power to continue running. This item is to provide portable generator to supply SG level indication.
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	NOLOSP	$519K	$746K	$463K	$673K	$1,000K	>$2,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
14	Install a gas turbine generator.	Increased availability of on-site AC power.	NOSBO	$1,495K	$2,158K	$1,334K	$1,947K	$2,869K	>$7,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 14 in Unit 1. See report section 7.3.	Cost Exceeds benefit.
17	Create a cross-tie for diesel fuel oil (multi-unit site).	Increased diesel generator availability.	SBO1	$36.1K	$52.0K	$32.2K	$47.0K	$69.2K	$500K	Expert Panel	Not Cost-Beneficial	No fuel oil cross-tie exists on Unit 2, neither between the Unit 2 trains nor to Unit 1. Implementation would require a modification since there are no existing valves large enough to provide even temporary connection ability. Cost exceeds benefit.
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	LOCA02	$22.1K	$32.8K	$19.6K	$29.8K	$40.3K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	LOCA02	$22.1K	$32.8K	$19.6K	$29.8K	$40.3K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
28	Add a diverse low pressure injection system.	Improved injection capability.	LOCA03	$2.2K	$3.4K	$1.9K	$3.2K	$3.6K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	LOCA03	$2.2K	$3.4K	$1.9K	$3.2K	$3.6K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	LOCA01	$83.8K	$122K	$74.6K	$110K	$159K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injection systems.	LOCA02	$22.1K	$32.8K	$19.6K	$29.8K	$40.3K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	LOCA01	$83.8K	$122K	$74.6K	$110K	$159K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 8-1 BVPS Unit 2 SAMA Sensitivity Evaluation (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	CHG01	<$1K	<$1K	<$1K	<$1K	<$1K	>$300K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	RCPLOCA	$1,358K	$1,959K	$1,212K	$1,768K	$2,607K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	RCPLOCA	$1,358K	$1,959K	$1,212K	$1,768K	$2,607K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	CCW01	$6.0K	$8.7K	$5.4K	$7.9K	$11.4K	$130K	Expert Panel	Not Cost-Beneficial	Hardware modification required as well as procedure changes.
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	FW01	$27.2K	$39.8K	$24.2K	$36.1K	$50.9K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	DAFW	$1,810K	$2,612K	$1,615K	$2,358K	$3,474K	$3,000K	Expert Panel	Potentially Cost-Beneficial (because the upper bound sensitivity benefit exceeds the cost)	Cost to purchase pump, installation, piping, procedures, etc. to install a dedicated feedwater system similar to Unit 1 and would provide a significant reduction in CDF.
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	INSTAIR1	<$1K	<$1K	<$1K	<$1K	<$1K	>$100K	Expert Panel Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
94	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.	CONT01	$2,427K	$3,392K	$2,189K	$3,026K	$4,948K	$9,000K	Industry studies (NUREG 1437 supplements) with inflation	Not Cost-Beneficial	Some venting capability currently exists but the post-accident environment could preclude venting. A different vent was considered necessary to assure continued filtering.
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	H2BURN	$25.8K	$36.1K	$23.3K	$32.2K	$52.7K	>$500K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Hydrogen recombiners previously abandoned in place.
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	LOCA05	$8.5K	$12.9K	$7.4K	$11.8K	$14.7K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Have implemented RI-ISI.
107	Install a redundant containment spray system.	Increased containment heat removal ability.	CONT01	$2,428K	$3,392K	$2,189K	$3,026K	$4,948K	>$10,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds the benefit.
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	LOCA06	$135K	$191K	$121K	$171K	$269K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	CONT02	$20.1K	$28.6K	$18.0K	$25.7K	$39.6K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 8-1 BVPS Unit 2 SAMA Sensitivity Evaluation (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	LOCA06	$135K	$191K	$121K	$171K	$269K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Increased outage frequency/duration.
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	LOCA06A	<$1K	<$1K	<$1K	<$1K	<$1K	>$15K	Expert Panel	Not Cost-Beneficial	The PRA case to evaluate the benefit of this SAMA significantly over estimates the benefit. The PRA model does not contain a human error event for failure of the operators to isolate the ISLOCA since the leak pathway contains three check valves, all of which must fail for the ISLOCA to occur. If a human action is credited, the benefit would be extremely small. The results provided are from a sensitivity case comparing the baseline (in which credit is given for break isolation) with the elimination of all ISLOCAs. This is very conservative and still yields extremely small benefits.
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	NOSGTR	$165K	$234K	$149K	$210K	$329K	>$3,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	NOATWS	$4.8K	$8.0K	$4.1K	$7.5K	$6.4K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	NOATWS	$4.8K	$8.0K	$4.1K	$7.5K	$6.4K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	NOATWS	$4.8K	$8.0K	$4.1K	$7.5K	$6.4K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	NOATWS	$4.8K	$8.0K	$4.1K	$7.5K	$6.4K	>$100K	Expert Panel Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	NOATWS	$4.8K	$8.0K	$4.1K	$7.5K	$6.4K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 8-1 BVPS Unit 2 SAMA Sensitivity Evaluation (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	NOSLB	$1.7K	$2.4K	$1.5K	$2.2K	$3.1K	>$100K	Expert Panel Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	NOATWS	$4.8K	$8.0K	$4.1K	$7.5K	$6.4K	>$100K	Expert Panel Implementation will require plant modification.	Not Cost-Beneficial	Cost exceeds benefit.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve	Reduce release due to SGTR.	SGTR4	$86.4K	$122K	$77.6K	$109K	$172K	$50K	Expert Panel	Potentially Cost-Beneficial	SAMA is potentially cost beneficial. Loop stop valves are also not design to close against differential pressure and under accident conditions will not fully seat since hoses must be installed to provide pressure between the seats to fully seat the valve.
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	RCPLOCA	$1,358K	$1,959K	$1,212K	$1,768K	$2,607K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
169	Improve operator performance. Operator fails to align makeup to RWST - SGTR, secondary leak	Top 10 operator actions OPRWM1	HEP1	$10.7K	$15.1K	$9.6K	$13.5K	$21.3K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
170	Improve operator performance. Operator fails to manually trip reactor - ATWS	Top 10 operator actions OPROT1	HEP2	<$1K	$1.5K	<$1K	$1.4K	$1.7K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
171	Improve operator performance. Operator fails to realign main feedwater - no SI signal	Top 10 operator actions OPROF2	HEP3	$13.6K	$19.6K	$12.2K	$17.7K	$26.2K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
172	Improve operator performance. Operator fails to initiate AFW following transient	Top 10 operator actions OPROS6	HEP4	$42.6K	$61.2K	$38.0K	$55.2K	$82.3K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
173	Improve operator performance. Operator aligns spare battery charger 2-9 to 2-2	Top 10 operator actions OPRDC2	HEP5	$5.2K	$7.6K	$4.7K	$6.8K	$10.1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
174	Improve operator performance. Operator aligns spare battery charger 2-7 to 2-1	Top 10 operator actions OPRDC1	HEP6	$5.5K	$8.0K	$4.9K	$7.2K	$10.6K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
175	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB2	HEP7	$20.2K	$30.6K	$17.8K	$28.1K	$35.1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
176	Improve operator performance. Operator fails to trip RCP during loss of CCP	Top 10 operator actions OPROC1	HEP8	$6.4K	$9.3K	$5.7K	$8.5K	$12.1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1

Table 8-1 BVPS Unit 2 SAMA Sensitivity Evaluation (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
177	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB1	HEP9	$1.8K	$2.7K	$1.6K	$2.5K	$3.2K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
178	Improve operator performance. Operator fails to identify ruptured SG or initiate isolation	Top 10 operator actions OPRSL1	HEP10	$17.6K	$24.8K	$15.8K	$22.2K	$35.1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
179	Reduce risk contribution from fires originating in Zone CB-3, causing a total loss of main feedwater and auxiliary feedwater with subsequent failure of feed and bleed.	Elimination or improved mitigation of fires in this area.	FIRE05	$34.4K	$52.1K	$30.2K	$47.8K	$59.8K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
180	Reduce risk contribution from fires originating in zone CT-1, causing a total loss of service water.	Elimination or improved mitigation of fires in this area.	FIRE06	$202K	$292K	$181K	$264K	$389K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
181	Reduce risk contribution from fires originating in zone SB-4, causing a total loss of normal AC power with subsequent failure of emergency AC power and station crosstie leading to station blackout.	Elimination or improved mitigation of fires in this area.	FIRE07	$10.7K	$15.4K	$9.5K	$13.9K	$20.5K	$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
183	Reduce risk contribution from fires originating in zone CV-3, causing failure of component cooling water (thermal barrier cooling) and service water with subsequent failure of reactor coolant pump seal injection.	Elimination or improved mitigation of fires in this area.	FIRE09	$54.6K	$79.2K	$48.7K	$71.6K	$104K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
184	Reduce risk contribution from fires in EDG building, fire initiator DG1L1A.	Elimination or improved mitigation of fires in this area.	FIRE10	$164K	$237K	$147K	$214K	$316K	$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.. This represents 1/2 the cost; remainder associated with SAMA 185.
185	Reduce risk contribution from fires in EDG building, fire initiator DG2L1A.	Elimination or improved mitigation of fires in this area.	FIRE11	$163K	$236K	$146K	$213K	$314K	$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. This represents 1/2 the cost; remainder associated with SAMA 184.
186	Increase seismic ruggedness of the ERF Substation batteries. This refers only to the battery racks, not the entire structure.	Increased reliability of the ERF diesel following seismic events	SEISMIC1	$3.8K	$5.5K	$3.4K	$5.0K	$7.3K	$300K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 187 in Unit 1. See report section 7.3.	Unit 1 benefit - Reference U1 SAMA 187

Table 8-1 BVPS Unit 2 SAMA Sensitivity Evaluation (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
187	Reduce risk contribution from internal flooding in cable vault area, CV-2 735', by reducing the frequency of the event or by improvements in mitigation of the resulting flooding.	Eliminate or mitigate the consequences of a flood in this area.	FLOOD1D	<$1K	<$1K	<$1K	<$1K	<$1K	>$15K	Expert Panel	Not Cost-Beneficial	Source of flooding is a 4" fire water pipe that traverses the area. The PRA currently does not include credit for the procedure that is in place to isolate a leak/break in the subject piping; i.e., the PRA model does not contain the human error event for failure of the operators to isolate the flood source. If the human action is credited, the benefit for improvements in mitigate would be extremely small. The results provided are from a sensitivity case comparing a revised baseline (in which credit is given for break isolation) (FLOOD1D) with the elimination of this internal flooding scenario. This is very conservative and still yields extremely small benefits; no change in procedures or hardware would be cost-beneficial.
188	Reduce risk contribution from internal flooding in Safeguards building, N&S. (Source of flooding is a RWST line.	Eliminate or mitigate the consequences of a flood in this area.	FLOOD2	$63.4K	$91.5K	$56.6K	$82.6K	$122K	>$200K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
190	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	CONT01	$2,427K	$3,392K	$2,189K	$3,026K	$4,948K	>$10,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 186 in Unit 1. See report section 7.3.	Cost will exceed benefit due to cleanup costs and replacement power at opposite unit.

Note 1 – The current plant procedures and training meet current industry standards. The benefit calculation results provided in this table are based upon an arbitrary reduction in HEP of a factor of 3 and are provided solely to demonstrate the sensitivity of the model to change in the HEP. There are no additional specific procedure improvements that could be identified that would affect the result of the HEP calculations to this level of reduction. Therefore, it is expected that the idealistic benefits presented in the table are not achievable with procedure improvements only and would require additional hardware modifications. In all cases the costs of hardware and procedure changes would exceed the idealistic benefits presented in the table. These SAMAs are, therefore, screened as Not Cost Beneficial.

9 CONCLUSIONS

As a result of this analysis, the SAMAs identified in Table 9-1 have been identified as potentially cost beneficial, either directly or as a result of the sensitivity analyses. However, since the other potential improvements could result in a reduction in public risk, these SAMAs will be entered into the Beaver Valley Long-range Plan development process for further consideration.

Implementation of SAMA 3 would involve the purchase of a portable generator to supply power to the steam generator level instrumentation. The TDAFW pump does not require power to start or continue running.

Implementation of SAMA 78 would require removing the start-up feedwater pump skid (including main motor and associated auxiliary oil and seal water pumps and motors), and associated suction, discharge and recirculation piping and valves (including the current motor-operated and air-operated discharge valves). These components would be replaced by a smaller pump and motor skid, and associated piping and valves. The new suction and recirculation piping and valves would be run to an independent water source outside of the Turbine Building. The new discharge piping and valves (including a new motor-operated discharge valve), would be run to the abandoned location on the main feedwater header. Any disconnected, original power and control cabling (and associated circuit breakers, control switches and alarms) from the ERF substation and Unit 2 Control Room would be reused where possible.

Implementation of SAMA 164 would involve two actions. The first is a procedural change to direct the operators to close the RCS loop stop valves to isolate a steam generator that has had a tube failure. The second involves purchase or manufacture of a gagging device that could be used to close a stuck open steam generator safety valve (i.e., faulted) on the ruptured steam generator prior to core damage in SGTR events.

None of the SAMAs in Table 9-1 have been found to be aging-related.

Table 9-1 BVPS-2 Potentially Cost Beneficial SAMAs

BV2 SAMA Number	Potential Improvement	Discussion	Additional Discussion
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	This would provide a system similar to the dedicated AFW pump present at Unit 1.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	

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APPENDIX A – PRA RUNS FOR SELECTED SAMA CASES

Explanation of Appendix A Contents

This appendix describes each of the SAMA evaluation cases. An evaluation case is an evaluation of plant risk using a plant PRA model that considers implementation of the evaluated SAMA. The case-specific plant configuration is defined as the plant in its baseline configuration with the model modified to represent the plant after the implementation of a particular SAMA. As indicated in the main report, these model changes were performed in a manner expected to bound the change in risk that would actually be expected if the SAMA were implemented. This approach was taken because the actual designs for the SAMAs have not been developed.

Each analysis case is described in the following pages. Each case description contains a description of the physical change that the case represents along with a description of the SAMAs that are being evaluated by this specific case.

The PDS frequencies calculated as a result of the PRA model quantification for each SAMA case is presented in Table A-5.

Case INSTAIR1

Description: This case is used to determine the benefit of replacing the air compressors. For the purposes of the analysis, a single bounding condition was performed, which assumed the station instrument air system does not fail.

Case NOATWS

Description: This case is used to determine the benefit of eliminating all Anticipated Transient Without Scram (ATWS) events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.

Case NOSGTR

Description: This case is used to determine the benefit of eliminating all steam generator tube rupture (SGTR) events. This allows evaluation of various possible improvements that could reduce the risk associated with SGTR events. For the purposes of this analysis, a single bounding analysis was performed which assumed that SGTR events do not occur.

Case NOLOSP

Description: This case is used to determine the benefit of eliminating all loss of offsite power (LOSP) events, both as the initiating event and subsequent to a different initiating event. This allows evaluation of various possible improvements that could reduce the risk associated with LOSP events. For the purposes of the analysis, a single bounding analysis was performed which assumed that LOSP events do not occur, both as an initiating event and subsequent to a different initiating event.

Case NOSBO

Description: This case is used to determine the benefit of eliminating all station blackout (SBO) events. This allows evaluation of possible improvements related to SBO sequences. For the purpose of the analysis, a single bounding analysis is performed that assumes the emergency AC power supplies do not fail.

Case NOSLB

Description: This case is used to determine the benefit of installing secondary side guard pipes to the main steam isolation valves (MSIVs). This would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. For the purposes of the analysis, a single bounding analysis was performed which assumed that no steam line break (SLB) events occur.

Case HEP1

Description: The probability of basic event OPRWM1, Operator aligns makeup to the RWST, given a SGTR with secondary leakage, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP2

Description: The probability of basic event OPROT1, Operator manually trips reactor within 1 minute, given automatic trip failed, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP3

Description: The probability of basic event OPROF2, Operator realigns Main Feedwater - no SI signal present, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP4

Description: The probability of basic event OPROS6, Operator manually actuates AFW following a transient, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP5

Description: The probability of basic event OPRDC2, Operator aligns spare battery charger 2-9 to BAT-CHG2-2, given that it has failed and the batteries are supplying the bus, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP6

Description: The probability of basic event OPRDC12, Operator aligns spare battery charger 2-7 to BAT-CHG2-1, given that it has failed and the batteries are supplying the bus, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP7

Description: The probability of basic event OPROB2, Operator initiates Bleed & Feed when AFW fails, given that MFW restoration was not attempted, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP8

Description: The probability of basic event OPROC1, Operator trips the RCPs during a loss of all CCP, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP9

Description: The probability of basic event OPROB1, Operator initiates Bleed & Feed when AFW fails, after attempting to realign MFW, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP10

Description: The probability of basic event OPRSL1, Operator identifies ruptured S/G and initiates isolation, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case LOCA01

Description: This case is used to determine the benefit of eliminating all small LOCA events. This case was used to evaluate improvements that would help mitigate small LOCA events.

Case LOCA02

Description: Assume High Pressure Injection system does not fail. This case was used to evaluate improvements in the high pressure injection systems.

Case LOCA03

Description: Assume Low Pressure Injection system does not fail. This case was used to evaluate improvements in the low pressure injection system.

Case LOCA04

Description: Assume the Refueling Water Storage Tank (RWST) inventory never depletes. This case was used to evaluate improvements that provide refill or backup to the RWST.

Case LOCA05

Description: Eliminate all piping failure LOCAs. No change for non-piping failure LOCAs such as SGTR, RCP Seal LOCA, stuck open SRV/PORV or ISLOCA. This case was used to evaluate improvements that would lower the probability of piping system LOCA events.

Case LOCA06

Description: Assume no ISLOCA events occur. This case is used to determine the benefit of eliminating all ISLOCA events.

Case DC1

Description: Assume the DC power system does not fail or deplete. This case is used to determine the impact of the improvement in the DC power system.

Case CHG01

Description: Eliminate the dependency of the charging pumps on cooling water. This case is used to determine the benefit of removing the charging pumps dependency on cooling water.

Case SW01

Description: Eliminate the dependency of the service water pumps on DC power. This case is used to determine the benefit of enhancing the DC control power to the service water pumps.

Case CCW01

Description: This case is used to determine the benefit of improvement to the Component Cooling Water (CCW) system by assuming that CCW pumps do not fail.

Case FW01

Description: Eliminate loss of feedwater initiating events. This case is used to determine the benefit of improvements to the feedwater and feedwater control systems.

Case RCPLOCA

Description: This case is used to determine the benefit of eliminating all RCP seal LOCA events except those associated with seismic events with a PGA greater than 0.35g. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.

Case CONT01

Description: This case is used to determine the benefit of eliminating all containment failures due to overpressurization. This is analogous to considering a perfect filter with perfect hardware and perfect operation implemented on sequences that lead to any containment overpressure condition.

Case H2BURN

Description: Eliminate all hydrogen ignition and detonation events. This case is used to determine the benefit of eliminating all hydrogen ignition and burns.

Case CONT02

Description: Assume failures of containment isolation do not occur. This case is used to determine the benefit of eliminating all containment isolation failures.

Case FLOOD1

Description: This case eliminates the internal cable vault flooding from fire water. This case is used to evaluate improvements that would help eliminate or mitigate this flood.

Case FLOOD2

Description: This case eliminates the safeguards building N&S rooms internal flood. This case is used to evaluate improvements that would help eliminate or mitigate this flood.

Case FIRE05

Description: This case eliminates the fires in zone CB-3 that cause a total loss of main feedwater and auxiliary feedwater with subsequent failure of bleed and feed. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE06

Description: This case eliminates the fires in zone CT-1 that cause a total loss of service water. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE07

Description: This case eliminates the fires in zone SB-4 that cause a total loss of normal AC power with subsequent failure of emergency AC power and station crosstie leading to station blackout. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE08

Description: This case eliminates the fires in zone CV-1 that cause failure of service water train A. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE09

Description: This case eliminates the fires in zone CV-3 that cause failure of component cooling water (thermal barrier cooling) and service water with subsequent failure of reactor coolant pump seal injection. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE10

Description: This case eliminates the fires in zone DG1L1A, Emergency Diesel Generator (EDG) building. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE11

Description: This case eliminates the fires in zone DG2L1A, EDG building. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case SBO1

Description: This case eliminates the failures of the EDGs due to failures in the fuel oil system. This case is used to evaluate the installation of a diesel fuel oil cross-tie between the units.

Case SEISMIC1

Description: This case reduces the failure of the Emergency Response Facility (ERF) Substation batteries due to seismic events (by setting the ERF Substation battery seismic capacity equivalent to the Unit 2 125V DC Emergency battery capacity). This case is used to evaluate the benefit of increasing the seismic ruggedness of the ERF Substation battery racks.

Case DAFW (new base case)

Description: This case is developed to assess the impact of the addition of a dedicated AFW pump powered by the ERF diesel generator and of a portable diesel generator for unlimited steam generator level instrumentation.

Case CONT01D

Description: This case is used to assess the impact of the already defined case CONT01 to the new base case DAFW.

Case NOSGTRD

Description: This case is used to assess the impact of the already defined case NOSGTR to the new base case DAFW.

Case CCW01D

Description: This case is used to assess the impact of the already defined case CCW01 to the new base case DAFW.

Case RCPLOCAD

Description: This case is used to assess the impact of the already defined case RCPLOCA to the new base case DAFW.

Case CHG01D

Description: This case is used to assess the impact of the already defined case CHG01 to the new base case DAFW.

Case NOSBOD

Description: This case is used to assess the impact of the already defined case NOSBO to the new base case DAFW.

Cases FLOOD1A, FLOOD1B, FLOOD1C, and FLOOD1D

Description: These cases were used to evaluate improved detection of piping degradation for the fire water piping that causes the flooding of CV-1. The CVFLF bin frequencies were divided by the initiating event frequency to obtain a conditional core damage (release bin) probability.

Sensitivity cases were performed by assuming that if an NDE was performed on the fire water piping the initiating event frequency would be reduced by a factor of 10, 2, or 20. The new initiating event frequency was multiplied by the CCDP of each release bin and added this value to the associated FLOOD1 release bin frequency (the FLOOD1 bin frequencies are without any CVFLF contribution).

FLOOD1D was developed analogously but the CCDP for each bin was multiplied by an HEP of 1E-3 to estimate the likelihood of the operators failing to isolate the leakage from the fire water pipe given the existing procedure which responds to the fire protection water flow alarm. The CCDPs, the HEP and the initiating event frequency were recombined to arrive at the fin frequencies.

Cases SGTR2, SGTR3, SGTR4, and SGTR5

Description: The SG sensitivity cases were performed assuming that the operator action to close the RCS loop stop valves or to gag closed the stuck-open SG SV would only have a 50% probability of success, as opposed to the 100% success probability assumed in the NOSGTR maximum benefit case. To perform the SG sensitivity cases, the sum of SGTR release bin frequencies were divided by the single SGTR initiating event frequency (1.6059E-03) to obtain the SGTR conditional core damage probabilities for each release bin. The following describes how these SGTR release bin frequency sums and conditional release bin frequencies were applied to each sensitivity case.

For the SGTR2 case, where the operators gag a stuck-open SV, only the unscrubbed containment bypass release bin frequency (BV18) would be impacted. Since the assumed operator action to gag closed the stuck-open SG SV has a 50% probability of success, the SGTR BV18 release bin frequency was multiplied by 0.5. However, since the total CDF from SGTRs would not change from performing this action, the other 50% of the BV18 release bin frequency was added to the scrubbed small release bin frequency (BV20). The remaining SGTR release bin frequency sums remained unchanged. These new SGTR bin frequencies were then added to the NOSGTR release bin frequencies to obtain the SGTR2 sensitivity case release bin frequencies.

For the SGTR3 case, where the operators close the RCS loop stop valves, all of the SGTR release bin frequencies are impacted, since this action would essentially terminate the SGTR. Since the assumed operator action to perform this action has a 50% probability of success, the SGTR initiating event frequency was multiplied by 0.5. This new initiating event frequency (8.0295E-04) was then multiplied by each of the SGTR conditional release bin probabilities. The resultant new SGTR bin frequencies were then added to the NOSGTR release bin frequencies to obtain the SGTR3 sensitivity case release bin frequencies.

For the SGTR4 case, where the operators close the RCS loop stop valves and gag a stuck-open SV, all of the SGTR release bin frequencies are impacted, since this action would essentially terminate the SGTR. Since the assumed operator action to perform this action has a 50% probability of success, the SGTR initiating event frequency was multiplied by 0.5. This new initiating event frequency (8.0295E-04) was then multiplied by each of the SGTR conditional release bin probabilities to obtain revised SGTR bin frequencies. Additionally, the unscrubbed containment bypass release bin frequency (BV18) would be reduced by a 50% probability of success for terminating the unscrubbed containment bypass release. Therefore, the revised SGTR BV18 release bin frequency was further reduced by multiplying it by 0.5, and the other 50% of the revised BV18 release bin frequency was added to the revised scrubbed small release bin frequency (BV20). These new SGTR bin frequencies were then added to the NOSGTR release bin frequencies to obtain the SGTR4 sensitivity case release bin frequencies.

For the SGTR5 case, where the steam generators were replaced, all of the SGTR release bin frequencies are impacted, since this would reduce the frequency of having an SGTR. The new SGTR initiating event frequency was assumed to be same as the Unit 1 SGTR frequency, where the replacement steam generators were already implemented. This new initiating event frequency (6.9656E-04) was then multiplied by each of the SGTR conditional release bin probabilities. These new SGTR bin frequencies were then added to the NOSGTR release bin frequencies to obtain the SGTR5 sensitivity case release bin frequencies.

Table A-5
BVPS Unit 2 Release Category Frequency Results Obtained From SAMA Cases

BV2 RELEASE CATEGORIES	U2BASE	INSTAIR1	NOATWS	NOLOSP	NOSBO	NOSGTR	NOSLB	HEP1	HEP2	HEP3
Intact	1.20E-06	1.20E-06	1.05E-06	1.15E-06	1.02E-06	1.20E-06	1.19E-06	1.20E-06	1.19E-06	1.20E-06
ECF-VSEQ	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07
ECF-SGTR	1.25E-07	1.25E-07	1.24E-07	7.40E-08	1.21E-07	0.00E+00	1.25E-07	1.18E-07	1.24E-07	1.24E-07
ECF-DCH	3.78E-09	3.79E-09	3.78E-09	3.27E-09	1.92E-09	3.78E-09	3.78E-09	3.78E-09	3.78E-09	3.77E-09
SECF-VSEQ	3.67E-06	3.67E-06	3.67E-06	3.53E-06	3.63E-06	3.43E-06	3.67E-06	3.66E-06	3.67E-06	3.67E-06
SECF-LOCI	1.13E-07	1.13E-07	1.12E-07	1.11E-07	9.72E-08	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07
SECF-BV5	2.70E-08	2.70E-08	2.70E-08	2.59E-08	1.79E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08
LATE-LARGE	1.27E-08	1.27E-08	1.08E-08	1.22E-08	1.18E-08	1.27E-08	1.26E-08	1.27E-08	1.25E-08	1.26E-08
LATE-SMALL	1.84E-05	1.84E-05	1.84E-05	1.60E-05	1.03E-05	1.84E-05	1.84E-05	1.84E-05	1.84E-05	1.83E-05
LATE-H2BURN	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
LATE-BMMT	1.81E-07	1.81E-07	1.74E-07	1.29E-07	1.13E-07	1.81E-07	1.81E-07	1.81E-07	1.80E-07	1.81E-07
CDF	2.40E-05	2.40E-05	2.39E-05	2.14E-05	1.56E-05	2.37E-05	2.40E-05	2.40E-05	2.40E-05	2.40E-05

Table A-1
BVPS Unit 2 Release Category Frequency Results Obtained From SAMA Cases (Cont.)

BV2 RELEASE CATEGORIES	HEP4	HEP5	HEP6	HEP7	HEP8	HEP9	HEP10	LOCA01	LOCA02	LOCA03
Intact	1.19E-06	1.20E-06	1.20E-06	9.57E-07	1.19E-06	1.18E-06	1.20E-06	1.14E-06	1.04E-06	1.17E-06
ECF-VSEQ	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07
ECF-SGTR	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	9.19E-08	1.25E-07	1.18E-07	1.25E-07
ECF-DCH	3.75E-09	3.78E-09	3.78E-09	3.74E-09	3.77E-09	3.78E-09	3.78E-09	3.91E-09	3.75E-09	3.78E-09
SECF-VSEQ	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.68E-06	3.67E-06	3.66E-06	3.67E-06
SECF-LOCI	8.91E-08	1.13E-07	1.13E-07	7.49E-08	1.13E-07	1.10E-07	1.13E-07	1.12E-07	1.05E-07	1.13E-07
SECF-BV5	1.25E-08	2.70E-08	2.70E-08	2.69E-08	2.67E-08	2.70E-08	2.70E-08	2.55E-08	2.70E-08	2.70E-08
LATE-LARGE	1.25E-08	1.27E-08	1.27E-08	1.00E-08	1.26E-08	1.24E-08	1.27E-08	1.20E-08	1.15E-08	1.24E-08
LATE-SMALL	1.83E-05	1.84E-05	1.84E-05	1.84E-05	1.84E-05	1.84E-05	1.84E-05	1.80E-05	1.84E-05	1.84E-05
LATE-H2BURN	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
LATE-BMMT	1.80E-07	1.81E-07	1.81E-07	1.73E-07	1.78E-07	1.80E-07	1.81E-07	8.92E-08	1.60E-07	1.61E-07
CDF	2.38E-05	2.40E-05	2.40E-05	2.37E-05	2.40E-05	2.40E-05	2.40E-05	2.35E-05	2.38E-05	2.40E-05

Table A-1
BVPS Unit 2 Release Category Frequency Results Obtained From SAMA Cases (Cont.)

BV2 RELEASE CATEGORIES	LOCA04	LOCA05	LOCA06	CCW01	CONT01	FW01	DC1	CHG01	CONT02	RCPLOCA
Intact	1.20E-06	1.13E-06	1.20E-06	1.19E-06	1.16E-05	1.12E-06	1.20E-06	1.20E-06	1.20E-06	3.82E-10
ECF-VSEQ	2.80E-07	2.80E-07	0.00E+00	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	0.00E+00
ECF-SGTR	1.13E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	0.00E+00
ECF-DCH	3.78E-09	3.78E-09	3.78E-09	3.78E-09	2.74E-10	3.76E-09	1.20E-09	3.78E-09	3.76E-09	2.04E-09
SECF-VSEQ	3.64E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.63E-06	3.67E-06	3.67E-06	3.31E-06
SECF-LOCI	1.13E-07	1.13E-07	1.13E-07	1.13E-07	3.72E-08	1.10E-07	1.13E-07	1.13E-07	7.60E-08	2.63E-06
SECF-BV5	2.70E-08	2.70E-08	2.70E-08	2.69E-08	2.62E-08	2.56E-08	2.65E-08	2.70E-08	7.69E-10	6.85E-07
LATE-LARGE	1.26E-08	1.15E-08	1.27E-08	1.26E-08	0.00E+00	1.16E-08	1.27E-08	1.27E-08	1.27E-08	4.49E-13
LATE-SMALL	1.84E-05	1.84E-05	1.84E-05	1.84E-05	0.00E+00	1.83E-05	9.93E-06	1.84E-05	1.84E-05	8.35E-06
LATE-H2BURN	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
LATE-BMMT	1.75E-07	1.54E-07	1.81E-07	1.81E-07	8.29E-06	1.76E-07	1.81E-07	1.81E-07	1.81E-07	1.09E-10
CDF	2.40E-05	2.39E-05	2.37E-05	2.40E-05	2.40E-05	2.38E-05	1.55E-05	2.40E-05	2.40E-05	1.50E-05

Table A-1

BVPS Unit 2 Release Category Frequency Results Obtained From SAMA Cases (Cont.)

BV2 RELEASE CATEGORIES	H2BURN	SW01	FLOOD1	FLOOD2	FIRE05	FIRE06	FIRE07	FIRE08	FIRE09	FIRE10
Intact	1.28E-06	1.20E-06	1.20E-06	1.20E-06	7.96E-07	1.20E-06	1.20E-06	1.20E-06	1.16E-06	1.19E-06
ECF-VSEQ	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07
ECF-SGTR	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07
ECF-DCH	3.77E-09	3.78E-09	3.78E-09	3.73E-09	3.71E-09	3.74E-09	3.77E-09	3.78E-09	3.72E-09	3.55E-09
SECF-VSEQ	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06
SECF-LOCI	3.85E-08	1.13E-07	1.13E-07	1.13E-07	4.93E-08	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07
SECF-BV5	2.70E-08	2.70E-08	2.70E-08	2.68E-08	2.67E-08	2.70E-08	2.70E-08	2.70E-08	2.61E-08	2.68E-08
LATE-LARGE	0.00E+00	1.27E-08	1.27E-08	1.27E-08	8.19E-09	1.27E-08	1.27E-08	1.27E-08	1.24E-08	1.26E-08
LATE-SMALL	1.84E-05	1.84E-05	1.78E-05	1.81E-05	1.84E-05	1.73E-05	1.84E-05	1.84E-05	1.81E-05	1.75E-05
LATE-H2BURN	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
LATE-BMMT	1.87E-07	1.81E-07	1.81E-07	1.81E-07	1.66E-07	1.81E-07	1.81E-07	1.81E-07	1.53E-07	1.77E-07
CDF	2.40E-05	2.40E-05	2.34E-05	2.37E-05	2.35E-05	2.29E-05	2.40E-05	2.40E-05	2.37E-05	2.31E-05

Table A-1
BVPS Unit 2 Release Category Frequency Results Obtained From SAMA Cases (Cont.)

BV2 RELEASE CATEGORIES	FIRE11	SEISMIC1	SBO1	FLOOD1A	FLOOD1B	FLOOD1C	SGTR2	SGTR3	SGTR4	SGTR5
Intact	1.19E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06
ECF-VSEQ	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07
ECF-SGTR	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	6.26E-08	6.26E-08	3.13E-08	5.43E-08
ECF-DCH	3.55E-09	3.77E-09	3.74E-09	3.78E-09	3.78E-09	3.78E-09	3.78E-09	3.78E-09	3.78E-09	3.78E-09
SECF-VSEQ	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.74E-06	3.55E-06	3.58E-06	3.54E-06
SECF-LOCI	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07
SECF-BV5	2.68E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08
LATE-LARGE	1.26E-08	1.27E-08	1.26E-08	1.27E-08	1.27E-08	1.27E-08	1.27E-08	1.27E-08	1.27E-08	1.27E-08
LATE-SMALL	1.75E-05	1.84E-05	1.82E-05	1.79E-05	1.81E-05	1.78E-05	1.84E-05	1.84E-05	1.84E-05	1.84E-05
LATE-H2BURN	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
LATE-BMMT	1.79E-07	1.81E-07	1.80E-07	1.81E-07	1.81E-07	1.81E-07	1.81E-07	1.81E-07	1.81E-07	1.81E-07
CDF	2.31E-05	2.40E-05	2.38E-05	2.35E-05	2.37E-05	2.35E-05	2.40E-05	2.38E-05	2.38E-05	2.38E-05

BV2 RELEASE CATEGORIES	Mod Base for SAMA 118	LOCA06a	Mod Base for SAMA 187	FLOOD1
Intact	1.20E-06	1.20E-06	1.20E-06	1.20E-06
ECF-VSEQ	9.99E-10	0.00E+00	2.80E-07	2.80E-07
ECF-SGTR	1.25E-07	1.25E-07	1.25E-07	1.25E-07
ECF-DCH	3.78E-09	3.78E-09	3.78E-09	3.78E-09
SECF-VSEQ	3.67E-06	3.67E-06	3.67E-06	3.67E-06
SECF-LOCI	1.13E-07	1.13E-07	1.13E-07	1.13E-07
SECF-BV5	2.70E-08	2.70E-08	2.70E-08	2.70E-08
LATE-LARGE	1.27E-08	1.27E-08	1.27E-08	1.27E-08
LATE-SMALL	1.84E-05	1.84E-05	1.78E-05	1.78E-05
LATE-H2BURN	0.00E+00	0.00E+00	0.00E+00	0.00E+00
LATE-BMMT	1.81E-07	1.81E-07	1.81E-07	1.81E-07
CDF	2.37E-05	2.37E-05	2.34E-05	2.34E-05