U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

NUREG-1437
Supplement 54

Generic Environmental Impact Statement for License Renewal of Nuclear Plants

Supplement 54

Regarding Byron Station, Units 1 and 2

Draft Report for Comment

Office of Nuclear Reactor Regulation

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ABSTRACT

This supplemental environmental impact statement (SEIS) has been prepared in response to an application submitted by Exelon Generation Company, LLC (Exelon), to renew the operating license for Byron Station, Units 1 and 2 (Byron), for an additional 20 years.

This SEIS includes the preliminary analysis that evaluates the environmental impacts of the proposed action and alternatives to the proposed action. Alternatives considered include: new nuclear generation, coal-integrated gasification combined cycle (IGCC), natural gas combined-cycle (NGCC), combination (NGCC, wind, and solar generation), replacement power, and no renewal of the license (the no-action alternative).

The U.S. Nuclear Regulatory Commission (NRC) staff's preliminary recommendation is that the adverse environmental impacts of license renewal for Byron are not so great that preserving the option of license renewal for energy-planning decisionmakers would be unreasonable. This recommendation is based on the following:

- the analysis and findings in NUREG–1437, Volumes 1 and 2, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*;
- the Environmental Report submitted by Exelon;
- consultation with Federal, state, local, and tribal government agencies;
- the NRC's environmental review; and
- consideration of public comments received during the scoping process.

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EXECUTIVE SUMMARY

BACKGROUND

By letter dated May 29, 2013, Exelon Generation Company, LLC (Exelon), submitted an application to the U.S. Nuclear Regulatory Commission (NRC) to issue renewed operating licenses for Byron Station, Units 1 and 2 (Byron), for an additional 20-year period.

Pursuant to Title 10 of the *Code of Federal Regulations* 51.20(b)(2) (10 CFR 51.20(b)(2)), the renewal of a power reactor operating license requires preparation of an environmental impact statement (EIS) or a supplement to an existing EIS. In addition, 10 CFR 51.95(c) states that, in connection with the renewal of an operating license, the NRC shall prepare an EIS, which is a supplement to the Commission's NUREG-1437, *Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants*.

Upon acceptance of Exelon's application, the NRC staff began the environmental review process described in 10 CFR Part 51 by publishing a Notice of Intent to prepare a supplemental environmental impact statement (SEIS) and conduct scoping. In preparation of this SEIS for Byron, the NRC staff performed the following:

- conducted public scoping meetings on August 20, 2013, in Byron, Illinois;
- conducted a site audit at Byron from September 16 to 19, 2013;
- reviewed Exelon's Environmental Report (ER) and compared it to the GEIS;
- consulted with Federal, state, and local agencies;
- conducted a review of the issues following the guidance set forth in NUREG-1555, *Standard Review Plans for Environmental Reviews for Nuclear Power Plants, Supplement 1, Revision 1: Operating License Renewal*; and
- considered public comments received during the scoping process.

PROPOSED ACTION

Exelon initiated the proposed Federal action—issuance of a renewed power reactor operating licenses—by submitting an application for license renewal of Byron, for which the existing licenses (NPF-37and NPF-66) expire on October 31, 2024, and November 6, 2026, respectively. The NRC's Federal action is to decide whether to renew the license for an additional 20 years. In accordance with 10 CFR 2.109, if a licensee of a nuclear power plant files an application to renew an operating license at least 5 years before the expiration date of that license, the existing license will not be deemed to have expired until the safety and environmental reviews are completed and the NRC has made a final decision to either deny the application or issue a renewed license for the additional 20 years.

PURPOSE AND NEED FOR ACTION

The purpose and need for the proposed action (issuance of renewed licenses) is to provide an option that allows for power generation capability beyond the term of the current nuclear power plant operating license to meet future system generating needs. Such needs may be determined by other energy-planning decisionmakers, such as states, operators, and, where authorized, Federal agencies (other than NRC). This definition of purpose and need reflects the

NRC's recognition that, unless there are findings in the safety review required by the Atomic Energy Act or findings in the National Environmental Policy Act (NEPA) environmental analysis that would lead the NRC to reject a license renewal application, the NRC does not have a role in the energy-planning decisions as to whether a particular nuclear power plant should continue to operate.

ENVIRONMENTAL IMPACTS OF LICENSE RENEWAL

The SEIS evaluates the potential environmental impacts of the proposed action. The environmental impacts from the proposed action are designated as SMALL, MODERATE, or LARGE. As set forth in the GEIS, Category 1 issues are those that meet all of the following criteria:

- The environmental impacts associated with the issue are 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 characteristics.
- A single significance level (i.e., SMALL, MODERATE, or LARGE) has been assigned to the impacts, except for collective offsite radiological impacts from the fuel cycle and from high-level waste and spent fuel disposal.
- Mitigation of adverse impacts associated with the issue is considered in the analysis, and it has been determined that additional plant-specific mitigation measures are likely not to be sufficiently beneficial to warrant implementation.

> **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, important attributes of the resource.
>
> **LARGE:** Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource.

For Category 1 issues, no additional site-specific analysis is required in this SEIS unless new and significant information is identified. Chapter 4 of this SEIS presents the process for identifying new and significant information. Site-specific issues (Category 2) are those that do not meet one or more of the criteria for Category 1 issues; therefore, an additional site-specific review for these nongeneric issues is required, and the results are documented in the SEIS.

Neither Exelon nor NRC identified information that is both new and significant related to Category 1 issues that would call into question the conclusions in the GEIS. This conclusion is supported by the NRC's review of the applicant's ER and other documentation relevant to the applicant's activities, the public scoping process and substantive comments raised, and the findings from the environmental site audit conducted by the NRC staff. The NRC staff, therefore, relies upon the conclusions of the GEIS for all Category 1 issues applicable to Byron.

Table ES-1 summarizes the Category 2 issues relevant to Byron as well as the NRC staff's findings related to those issues. If the NRC staff determined that there were no Category 2 issues applicable for a particular resource area, the findings of the GEIS, as documented in Appendix B to Subpart A of 10 CFR Part 51, are incorporated for that resource area.

Table ES–1. Summary of NRC Conclusions Relating to Site-Specific Impacts of License Renewal

Resource Area	Relevant Category 2 Issues	Impacts
Land Use	None	SMALL
Air Quality	None	SMALL
Geology and Soils	None	SMALL
Surface Water Resources	Surface water use conflicts (plants with cooling ponds or cooling towers using makeup water from a river)	SMALL
Groundwater Resources	Groundwater use conflicts (plants with closed-cycle cooling systems that withdraw makeup water from a river)	SMALL
	Radionuclides released to groundwater	SMALL
Terrestrial Resources	Effects on terrestrial resources (noncooling system impacts)	SMALL
	Water use conflicts with terrestrial resources (plants with cooling ponds or cooling towers using makeup water from a river)	SMALL
Aquatic Resources	Water use conflicts with aquatic resources	SMALL
Special Status Species	Threatened or endangered species	No effect [a]
Historic and Cultural	Historic and cultural resources	No adverse effect [b]
Socioeconomics	None	SMALL
Human Health	Microbiological hazards to the public health (plants with cooling ponds or canals or cooling towers that discharge to a river)	SMALL
	Electric shock hazards	SMALL
Environmental Justice	Minority and low-income populations	See note below [c]
Waste Management	None	SMALL
Cumulative Impacts	Air Quality and Noise	SMALL
	Geology and Soils	SMALL
	Water Resources	SMALL
	Terrestrial Ecology	SMALL-MODERATE
	Aquatic Resources	MODERATE
	Historic and Cultural Resources	SMALL
	Socioeconomic	SMALL
	Human Health	SMALL
	Environmental Justice	See note below [c]
	Waste Management	SMALL
	Global Climate Change	MODERATE

Resource Area	Relevant Category 2 Issues	Impacts

(a) For Federally protected species, the NRC reports the effects from continued operation of Byron during the license renewal period in terms of its Endangered Species Act (ESA) findings of “no effect,” “may effect, but not likely to adversely effect,” or “may affect, and is likely to adversely affect.”

(b) The National Historic Preservation Act of 1966, as amended (NHPA) requires Federal agencies to consider the effects of their undertakings on historic properties.

(c) There would be no disproportionately high and adverse impacts to minority and low-income populations and subsistence consumption from continued operation of Byron during the license renewal period and from cumulative impacts.

SEVERE ACCIDENT MITIGATION ALTERNATIVES

Since the staff had not previously considered severe accident mitigation alternatives (SAMA) in an environmental impact statement or in an environmental assessment for Byron, 10 CFR 51.53(c)(3)(ii)(L) requires a consideration of alternatives to mitigate severe accidents in the course of the license renewal review. SAMAs are potential ways to reduce the risk or potential impacts of uncommon, but potentially severe accidents, and they may include changes to plant components, systems, procedures, and training.

The NRC staff reviewed Exelon’s ER evaluation of potential SAMAs. Based on the staff’s review, the NRC staff concluded that none of the potentially cost beneficial SAMAs relate to adequately managing the effects of aging during the period of extended operation. Therefore, they need not be implemented as part of the license renewal, pursuant to 10 CFR Part 54.

ALTERNATIVES

The NRC staff considered the environmental impacts associated with alternatives to license renewal. These alternatives include other methods of power generation and not renewing the Byron operating license (the no-action alternative). The feasible and commercially viable replacement power alternatives considered were:

- new nuclear;
- integrated gasification combined cycle (IGCC);
- natural gas combined-cycle (NGCC);
- a combination of NGCC, wind, and solar power; and
- purchased power.

The NRC staff initially considered a number of additional alternatives for analysis as alternatives to the license renewal of Byron; these were later dismissed because of technical, resource availability, or commercial limitations that currently exist and that the NRC staff believes are likely to continue to exist when the existing Byron licenses expire. The no-action alternative and the effects it would have were also considered by the NRC staff.

Where possible, the NRC staff evaluated potential environmental impacts for these alternatives located both at the Byron site and at some other unspecified alternate location. Alternatives considered, but dismissed, were:

- energy conservation and energy efficiency;
- solar power;

- wind power;
- biomass power;
- hydroelectric power;
- wave and ocean energy;
- fuel cells;
- delayed retirement;
- geothermal power;
- municipal solid waste;
- petroleum; and
- supercritical pulverized coal.

The NRC staff evaluated each alternative using the same resource areas that were used in evaluating impacts from license renewal.

PRELIMINARY RECOMMENDATION

The NRC staff's preliminary recommendation is that the adverse environmental impacts of license renewal for Byron are not so great that preserving the option of license renewal for energy-planning decisionmakers would be unreasonable. This recommendation is based on the following:

- the analyses and findings in the GEIS;
- the ER submitted by Exelon;
- the NRC staff's consultation with Federal, state, and local agencies;
- the NRC staff's independent environmental review; and
- the NRC staff's consideration of public comments received during the scoping process.

ABBREVIATIONS AND ACRONYMS

µL/L	microliter(s) per liter
µm	micrometer(s)
AADT	average annual daily traffic
ac	acre(s)
AC	alternating current
ACC	averted cleanup and decontamination costs
ACHP	Advisory Council on Historic Preservation
ADAMS	Agencywide Documents Access and Management System
AEA	Atomic Energy Act of 1954 (as amended)
AEC	U.S. Atomic Energy Commission
AFW	auxiliary feedwater
ALARA	as low as is reasonably achievable
AMSAC	ATWS mitigating system actuation circuitry
ANL	Argonne National Laboratory
ANS	American Nuclear Society
AOC	averted offsite property damage costs
AOE	averted occupational exposure
AOSC	averted onsite costs
AP	auxiliary power
APE	averted public exposure
	averted potential exposure
AQCR	Air Quality Control Region
ARERR	Annual Radiological Effluent Release Report
ASA	Acoustical Society of America
ASLB	Atomic Safety and Licensing Board (NRC)
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient(s) without scram
AWEA	American Wind Energy Association
AWT	Association of Water Technologies
BACT	best available control technology
BEA	Bureau of Economic Analysis
BLH	BLH Technologies, Inc.
BLM	Bureau of Land Management

BLS	Bureau of Labor Statistics
BMP	best management practice
BOEM	Bureau of Ocean Energy Management
BP	before present
BSER	best system of emission reduction
BTU/ft^3	British thermal unit(s) per cubic foot
Byron	Byron Station, Units 1 and 2
CAA	Clean Air Act
CAES	compressed air energy storage
CAIR	Clean Air Interstate Rule
Callaway Unit 2	Callaway Nuclear Power Plant Unit 2
CB&I	Chicago Bridge & Iron
CCS	carbon capture and storage
CCW	component cooling water
CDF	core damage frequency
CEQ	Council on Environmental Quality
C_{eq}/kWh	carbon equivalent per kilowatt-hour
CET	containment event tree
CFE	early containment failure
CFR	*Code of Federal Regulations*
cfs	cubic foot (feet) per second
CH_4	methane
CISEH	Center for Invasive Species and Ecosystem Health
CLB	current licensing basis/bases
cm	centimeter(s)
CO	carbon monoxide
CO_2	carbon dioxide
CO_2/MWh	carbon dioxide per megawatt hour
COL	combined license
ComEd	Commonwealth Edison
CPE	catch per effort
CRA	Conestoga-Rovers & Associates
CRMP	Cultural Resource Management Plant
CRMP	Cultural Resource Management Plant
CSAPR	Cross-State Air Pollution Rule

CVCS	chemical and volume control system
CWA	Clean Water Act
DAW	dry active waste
dBA	decibels adjusted
DBA	design-basis accident
DCEO	Department of Commerce and Economic Opportunity
div.	Division
DLOOP	dual unit loss(es) of offsite power
DMS	Diverse Mitigation System
DNPS	Dresden Nuclear Power Station
DOE	Department of Energy
DSEIS	draft supplemental environmental impact statement
DSIRE	Database of State Incentives for Renewables & Efficiency
DSM	demand-side management
EA	environmental assessment
EAI	Environmental Analysts, Inc.
EAV	equalized assessed value
ECCS	emergency core cooling system
EcoCAT	Ecological Compliance Assessment Tool
EFH	essential fish habitat
EIA	Energy Information Administration
EIS	environmental impact statement
ELF	extremely low frequency
ELPC	Environmental Law and Policy Center
Elv.	Elevation
EMF	electromagnetic field
EO	Executive Order
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
EPZ	emergency planning zone
ER	Environmental Report
ERC	Energy Recovery Council
ER-O	Environmental Report for Byron operation
ES	Environmental Services
ESA	Endangered Species Act of 1973, as amended

ESF	engineered safety feature
ESFAS	engineered safety features actuation system
ESI	Ecological Specialists, Inc.
ESP	early site permit
ESW	emergency service water
ET	Earth Tech, Inc.
Exelon	Exelon Generation Company, LLC
F&O	fact and observation
FD	fresh dead shell(s)
FERC	Federal Energy Regulatory Commission
Fermi Unit 3	Enrico Fermi Atomic Power Plant, Unit 3
FES	final environmental statement
FES-C	Final Environmental Statement for Byron construction
FES-O	Final Environmental Statement for Byron operation
FESOP	Federally Enforceable State Operating Permit
FHWA	Federal Highway Administration
FIVE	fire-induced vulnerability evaluation
FR	*Federal Register*
FRN	*Federal Register* notice
ft	foot (feet)
ft^2	square foot (feet)
ft^3	cubic foot (feet)
FW	feedwater
FWCA	Fish and Wildlife Coordination Act of 1934, as amended
FWS	U.S. Fish and Wildlife Service
g	gram(s)
gal	gallon(s)
GE	General Electric
GEIS	generic environmental impact statement
GHG	greenhouse gas
GI	generic issue
GL	generic letter
gpd	gallon(s) per day
gpm	gallon(s) per minute
Gt	gigatonne(s)

GWPS	gaseous waste processing system
H_2O	water vapor
ha	hectare(s)
HAI	healthcare-associated infections
HAP	hazardous air pollutant
HCLPF	high confidence in low probability of failure
HEP	human error probability
HFE	human failure event
HFO	high winds, floods, and other
hr	hour(s)
HRA	human reliability analysis
HRSG	heat recovery steam generator
HUD	U.S. Department of Housing and Urban Development
HX	heat exchanger
IAC	Illinois Administrative Code
IBA	Important Bird Area
IDNR	Illinois Department of Natural Resources
IDOT	Illinois Department of Transportation
IDPH	Illinois Department of Public Health
IEA	International Energy Agency
IEMA	Illinois Emergency Management Agency
IEPA	Illinois Environmental Protection Agency
IESPB	Illinois Endangered Species Protection Board
IGCC	integrated gasification combined cycle
IHPA	Illinois Historic Preservation Agency
ILCS	Illinois Compiled Statutes
ILGA	Illinois General Assembly
in.	inch(es)
INEEL	Idaho National Engineering and Environmental Laboratory
INHS	Illinois Natural History Survey
Invenergy	Invenergy, LLC
IPCC	Intergovernmental Panel on Climate Change
IPE	individual plant examination
IPEEE	individual plant examination(s) of external events
ISBE	Illinois State Board of Education

ISD	Integrated Surface Data
ISFSI	independent spent fuel storage installation
ISGS	Illinois State Geological Survey
ISLOCA	interfacing-systems loss-of-coolant accident
ISM	Illinois State Museum
JHEP	joint human error probability
km	kilometer(s)
km^2	square kilometer(s)
kW	kilowatt(s)
kWe	kilowatt(s) electric
L	liter(s)
L	live individual(s)
L/min	liter(s) per minute
L/s	liter(s) per second
lb	pound(s)
L_{dn}	day-night average sound level—the 24-hour A-weighted equivalent sound level, with a 10-decibel penalty applied to nighttime levels
L_{eq}	equivalent continuous noise level
LER	large, early release
LERF	large early release frequency
LIDAR	Light Detection and Ranging
LLW	low-level radioactive waste
LMFW	loss of main feedwater
LOCA	loss-of-coolant accident
LOOP	loss(es) of offsite power
Lpd	liters per day
LRA	license renewal application
m/s	meter(s) per second
m^2	square meter(s)
m^3	cubic meter(s)
m^3/s	cubic meter(s) per second
MAAP	Modular Accident Analysis Program
MACCS2	MELCOR Accident Consequence Code System 2
MACR	maximum averted cost-risk

MAE Center	Mid-America Earthquake Center
MATS	Mercury and Air Toxics Standards
MBTA	Migratory Bird Treaty Act
MCR	main control room
MDNR	Minnesota Department of Natural Resources
MELCOR	Methods for Estimation of Leakages and Consequences of Releases
mg/L	milligram(s) per liter
mgd	million gallons per day
mgy	million gallons per year
mGy	milligray
mi	mile(s)
mi^2	square mile(s)
MISO	Midcontinent Independent System Operator, Inc.
MMPA	Marine Mammal Protection Act
MMSHT	Michigan Mine Safety & Health Training
MMT	million metric tons
MODNR	Missouri Department of Natural Resources
MOV	motor-operated valve
mph	mile(s) per hour
mrad	millirad
mrem	millirem
MSA	Magnuson–Stevens Fishery Conservation and Management Act, as amended through 2006
mSv	millisievert
MT	metric ton(s)
MUR	measurement uncertainty recapture
MW	megawatt(s)
MWe	megawatt(s) electric
MWh	megawatt hour(s)
MWt	megawatt(s) thermal
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NAH	North American Hydro
NARUC	National Association of Regulatory Utility Commissioners

NASS	National Agricultural Statistics Service
NCDC	National Climatic Data Center
NCES	National Center for Education Statistics
NEA	Nuclear Energy Agency
NEI	Nuclear Energy Institute
NEIS	National Energy Information Service
NEPA	National Environmental Policy Act
NESC®	National Electrical Safety Code®
NETL	National Energy Technology Laboratory
NGCC	natural gas combined-cycle
NHL	National historic landmark
NHPA	National Historic Preservation Act of 1966, as amended
NIEHS	National Institute of Environmental Health Sciences
NMFS	National Marine Fisheries Service (of NOAA)
NO_2	nitrogen dioxide
NO_x	nitrogen oxide(s)
NP	National park
NPDES	National Pollutant Discharge Elimination System
NPL	National Priorities List
NPS	National Park Service
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NRHP	National Register of Historic Places
NRR	Nuclear Reactor Regulation, Office of (NRC)
NSR	New Source Review
NUREG	NRC technical report designation
NWCC	National Wind Coordinating Committee
O_3	ozone
OCPZD	Ogle County Planning & Zoning Department
ODCM	Offsite Dose Calculation Manual
OECD	Organisation for Economic Co-operation and Development
OECR	offsite economic cost risk
ORNL	Oak Ridge National Laboratory
OSH	Occupational Safety and Health
OSHA	Occupational Safety & Health Administration

PAM	primary amoebic meningoencephalitis
Pb	lead
PCB	polychlorinated biphenyl
pCi/L	picocurie(s) per liter
PDR	population dose risk
PDS	plant damage state
PEIS	programmatic environmental impact statement
PFC	perfluorocarbon
PIAT	payment in addition to taxes
PIMW	potentially infectious medical waste
PIN	Property Index Number
PJM	PJM Interconnection, LLC
PL	public law
PLS-CADD™	Power Line Systems—Computer Aided Design and Drafting
PM	particulate matter
PM_{10}	particulate matter with aerodynamic diameters of 10 micrometers or less
$PM_{2.5}$	particulate matter with aerodynamic diameters of 2.5 micrometers or less
PNNL	Pacific Northwest National Laboratory
PONAR	sampling device used to study composition of lake bottom or river bottom, named after Great Lakes scientists Powers, Ogle, Noble, Ayers, and Robertson
PORV	power-operated relief valve
PPA	Pollution Prevention Act of 1990
ppm	parts per million
PRA	probabilistic risk assessment
PSD	prevention of significant deterioration
PTE	potential to emit
PV	photovoltaic
PWR	pressurized-water reactor
RAI	request(s) for additional information
RCP	reactor coolant pump
RCRA	Resource Conservation and Recovery Act
RDS	Research and Development Solutions, LLC
rem	roentgen equivalent(s) man

REMP	radiological environmental monitoring program
RES	Office of Nuclear Regulatory Research
RHR	residual heat removal Regional Haze Rule
RM	river mile
ROI	region(s) of influence
ROW	right-of-way
RPC	replacement power cost
RPS	reactor protection system
RPV	reactor pressure vessel
RRW	risk reduction worth
RTO	Regional Transmission Organization
RWST	refueling water storage tank
SAFSTOR	safe storage, also called deferred dismantling; a decommissioning strategy in which the nuclear facility is maintained and monitored in a condition that allows the radioactivity to decay before dismantling the plant and decontaminating the property
SAMA	severe accident mitigation alternative
SAR	safety analysis report
SAT	system auxiliary transformer
SBO	station blackout
SCR	selective catalytic reduction
SCPC	supercritical pulverized coal
SDCI	State Data Center of Iowa
SDWIS	Safe Drinking Water Information System
SEIS	supplemental environmental impact statement
SER	safety evaluation report
SF_6	sulfur hexafluoride
SFU	Simon Fraser University
SG	steam generator
SGTR	steam generator tube rupture
SI	safety injection
SIP	State Implementation Plan
SMA	seismic margin assessment
SO_2	sulfur dioxide
SO_x	sulfur oxide(s)

spp.	species (plural)
SR	supporting requirement
SRM	staff requirements memorandum (memoranda)
SSC	structure, system, and component
SSEL	Safe Shutdown Equipment List
Sv	sievert(s)
SW	service water
SX	essential service water
t	U.S. short ton(s)
TAC	technical assignment control
TEEIC	Tribal Energy and Environmental Information Clearinghouse
Teledyne	Teledyne Brown Engineering Environmental Services
Tg	teragram(s)
TS	technical specification
U.S.	United States
U.S.C.	United States Code
UAT	unit auxiliary transformer
UFSAR	updated final safety analysis report
USACE	United States Army Corps of Engineers
USCB	U.S. Census Bureau
USDA	U.S. Department of Agriculture
USDHHS	U.S. Department of Health and Human Services
USFS	U.S. Forest Service
USGCRP	U.S. Global Change Research Program
USGS	U.S. Geological Survey
Vogtle Units 3 and 4	Vogtle Electric Generating Plant, Units 3 and 4
yd	yard(s)
yd^3	cubic yard(s)
W/m^2	watt(s) per square meter
WAPA	Western Area Power Administration
WAW	wet active waste
WCAP	Westinghouse Commercial Atomic Power
WDOA	Wisconsin Department of Administration
WHC	Wildlife Habitat Council
WSA	wet gas sulfuric acid

yd	yard(s)
yd^3	cubic yard(s)
yr	year

1.0 INTRODUCTION

Under the U.S. Nuclear Regulatory Commission's (NRC's) environmental protection regulations in Title 10, Part 51, of the *Code of Federal Regulations* (10 CFR 51)—which implement the National Environmental Policy Act (NEPA)—issuance of a new nuclear power plant operating license requires the preparation of an environmental impact statement (EIS).

The Atomic Energy Act of 1954 (AEA) specified that licenses for commercial power reactors can be granted for up to 40 years. NRC regulations (10 CFR 54.31) allow for an option to renew a license for up to an additional 20 years. The initial 40-year licensing period was based on economic and antitrust considerations rather than on technical limitations of the nuclear facility.

The decision to seek a license renewal rests entirely with nuclear power facility owners and, typically, is based on the facility's economic viability and the investment necessary to continue to meet NRC safety and environmental requirements. The NRC makes the decision to grant or deny license renewal based on whether the applicant has demonstrated that the environmental and safety requirements in the agency's regulations can be met during the period of extended operation.

1.1 Proposed Federal Action

Exelon Generation Company, LLC (Exelon), initiated the proposed Federal action by submitting an application for license renewal of Byron Station, Units 1 and 2 (Byron), for which the existing licenses (NPF-37and NPF-66) expire on October 31, 2024, and November 6, 2026. The NRC's Federal action is to decide whether to renew the license for an additional 20 years.

1.2 Purpose and Need for Proposed Federal Action

The purpose and need for the proposed action (issuance of a renewed 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 other energy-planning decisionmakers. This definition of purpose and need reflects the NRC's recognition that, unless there are findings in the safety review required by the AEA or findings in the NEPA environmental analysis that would lead the NRC to reject a license renewal application (LRA), the NRC does not have a role in the energy-planning decisions of state regulators and utility officials as to whether a particular nuclear power plant should continue to operate.

1.3 Major Environmental Review Milestones

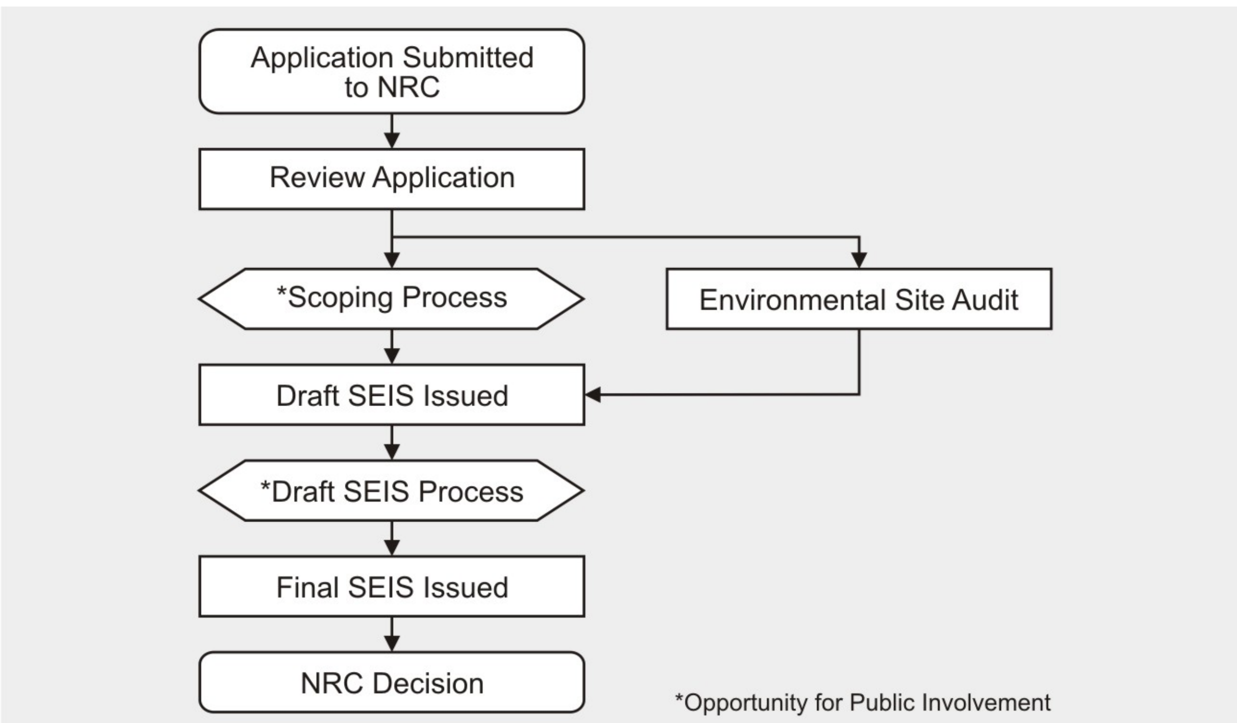
Exelon submitted an Environmental Report (ER) (Exelon 2013a) as part of its LRA (Exelon 2013b) in May 2013. After reviewing the LRA and ER for sufficiency, the NRC staff published a *Federal Register* Notice of Acceptability and Opportunity for Hearing (78 FR 44603) on July 24, 2013. Then, on August 6, 2013, the NRC published another notice in the *Federal Register* (78 FR 47800) on the intent to conduct scoping, thereby beginning the 60-day scoping period.

Two public scoping meetings were held on August 20, 2013, in Byron, Illinois (NRC 2013a). The comments received during the scoping process are presented in "Environmental Impact Statement, Scoping Process, Summary Report," published in May 2014 (NRC 2014). The scoping process summary report presents NRC responses to comments that the staff considered to be out of scope of the environmental license renewal review. The comments considered to be within the scope of the environmental license renewal review and the NRC responses are presented in Appendix A of this supplemental environmental impact statement (SEIS).

To independently verify information provided in the ER, NRC staff conducted a site audit at Byron in September 2013. During the site audit, NRC staff met with plant personnel, reviewed specific documentation, toured the facility, and met with interested local agencies. A summary of that site audit and the attendees is contained in “Summary of Site Audit in Support to the Environmental Review of the License Renewal Application for Byron Station, Units 1 and 2, (TAC Nos. MF1834 and MF1835)” published October 3, 2013 (NRC 2013c).

Upon completion of the scoping period and site audit, NRC staff compiled its findings in a draft SEIS. This document is made available for public comment for 75 days. During this time, NRC staff will host public meetings and collect public comments. Based on the information gathered, the NRC staff will amend the draft SEIS findings, as necessary, and publish the final SEIS. Figure 1–1 shows the major milestones of the NRC’s LRA environmental review.

Figure 1–1. Environmental Review Process



The NRC has established a license renewal process that can be completed in a reasonable period of time with clear requirements to ensure safe plant operation for up to an additional 20 years of plant life. The NRC staff conducts the safety review simultaneously with the environmental review. The staff documents the findings of the safety review in a safety evaluation report (SER). The findings in the SEIS and the SER are both factors in the NRC’s decision to either grant or deny the issuance of a renewed license.

1.4 Generic Environmental Impact Statement

The NRC staff performed a generic assessment of the environmental impacts associated with license renewal to improve the efficiency of its license renewal review. The *Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants*, NUREG-1437 (GEIS), (NRC 1996, 1999, 2013b), documented the results of the staff's systematic approach to evaluate the environmental consequences of renewing the licenses of individual nuclear power plants and operating them for an additional 20 years. The staff analyzed in detail and resolved those environmental issues that could be resolved generically in the GEIS. The GEIS was originally issued in 1996, Addendum 1 to the GEIS was issued in 1999, and Revision 1 to the GEIS was issued in 2013. Unless otherwise noted, all references to the GEIS include the GEIS, Addendum 1, and Revision 1.

The GEIS establishes separate environmental impact issues for the NRC staff to independently verify. Of these issues, the NRC staff determined that some generic issues are generic to all plants (Category 1). Other issues do not lend themselves to generic consideration (Category 2 or uncategorized). The staff evaluated these issues on a site-specific basis in the SEIS. Appendix B to Subpart A of 10 CFR 51 provides a summary of the staff findings in the GEIS.

For each potential environmental issue, in the GEIS the NRC staff:

- describes the activity that affects the environment,
- identifies the population or resource that is affected,
- assesses the nature and magnitude of the impact on the affected population or resource,
- characterizes the significance of the effect for both beneficial and adverse effects,
- determines whether the results of the analysis apply to all plants, and
- considers whether additional mitigation measures would be warranted for impacts that would have the same significance level for all plants.

The NRC's standard of significance for impacts was established using the Council on Environmental Quality terminology for "significant." The NRC established three levels of significance for potential impacts—SMALL, MODERATE, and LARGE, as defined below.

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, important attributes of the resource.

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

> **Significance** indicates the importance of likely environmental impacts and is determined by considering two variables: **context** and **intensity**.
>
> **Context** is the geographic, biophysical, and social context in which the effects will occur.
>
> **Intensity** refers to the severity of the impact, in whatever context it occurs.

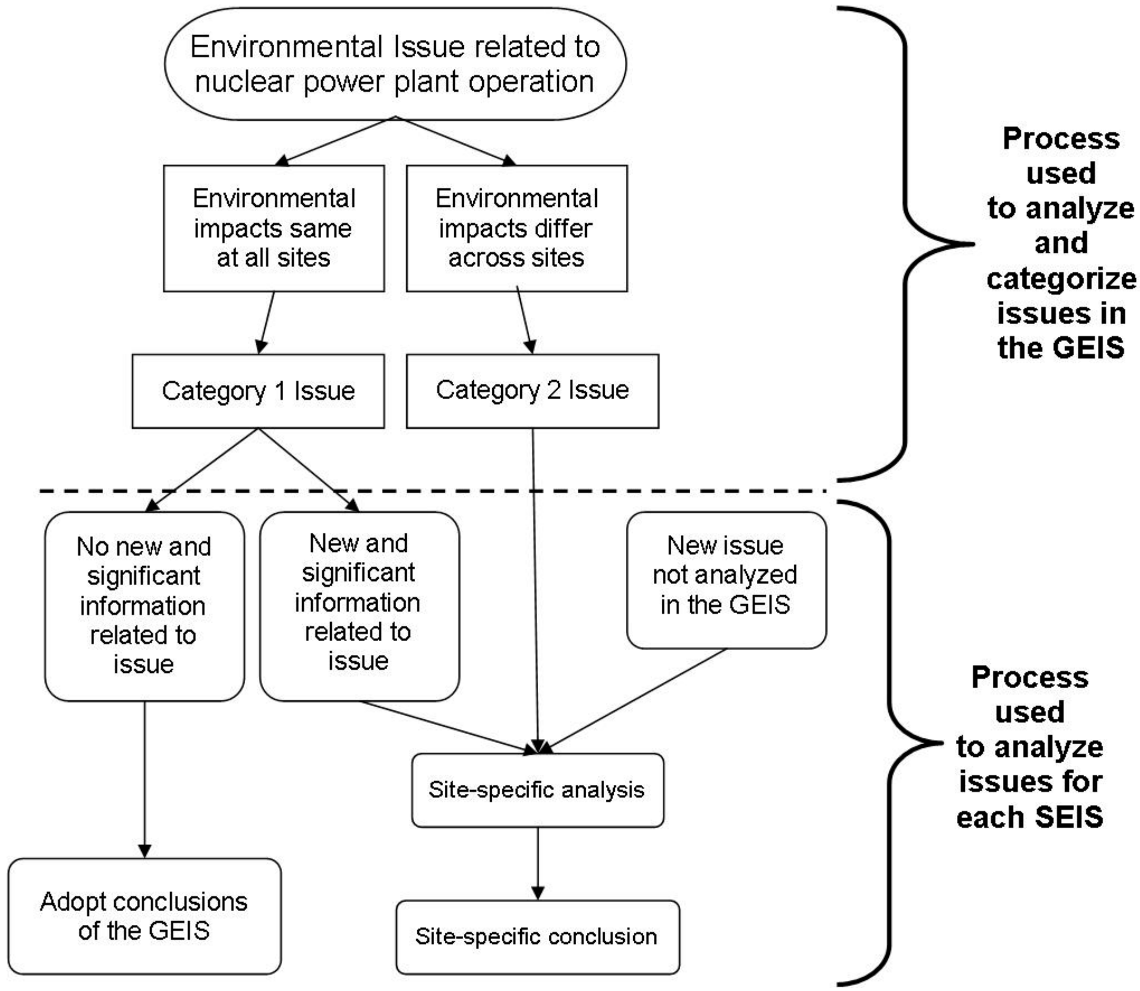
The GEIS includes a determination of whether the analysis of the environmental issue could be applied to all plants and whether additional mitigation measures would be warranted. Issues are assigned a Category 1 or a Category 2 designation. As set forth in the GEIS, Category 1 issues are those that meet the following criteria:

- The environmental impacts associated with the issue have been determined to apply either to all plants or, for some issues, to plants having a specific type of cooling system or other specified plant or site characteristics.
- A single significance level (i.e., SMALL, MODERATE, or LARGE) has been assigned to the impacts (except for collective offsite radiological impacts from the fuel cycle and from high-level waste and spent fuel disposal).
- Mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that additional plant-specific mitigation measures are likely not to be sufficiently beneficial to warrant implementation.

For generic issues (Category 1), no additional site-specific analysis is required in the SEIS unless new and significant information is identified. The process for identifying new and significant information for site-specific analysis is presented in Chapter 4. Site-specific issues (Category 2) are those that do not meet one or more of the criteria of Category 1 issues; therefore, additional site-specific review for these issues is required. A site-specific analysis is required for 17 of those 78 issues evaluated in the GEIS. Figure 1–2 illustrates this process. The results of that site-specific review are documented in the SEIS.

Figure 1–2. Environmental Issues Evaluated for License Renewal

In the GEIS, the NRC evaluated 78 issues.
A site-specific analysis is required for 17 of those 78 issues.



1.5 Supplemental Environmental Impact Statement

The SEIS presents an analysis that considers the environmental effects of the continued operation of Byron, alternatives to license renewal, and mitigation measures for minimizing adverse environmental impacts. Chapter 4 contains analysis and comparison of the potential environmental impacts from alternatives, while Chapter 5 presents the recommendation of the NRC on whether the environmental impacts of license renewal are so great that preserving the option of license renewal would be unreasonable. The final recommendation will be made after consideration of comments received on the draft SEIS during the public comment period.

In the preparation of the SEIS for Byron, the NRC staff carried out the following activities:

- reviewed the information provided in Exelon's ER;
- consulted with Federal agencies, state and local agencies, and tribal nations;

- conducted an independent review of the issues during site audit; and
- considered the public comments received for the review (during the scoping process).

New and significant information - To merit additional review, information must be both "new" and "significant," and it must bear on the proposed action or its impacts.

New information can be identified from many sources, including the applicant, the NRC, other agencies, or public comments. If a new issue is revealed, it is first analyzed to determine whether it is within the scope of the license renewal environmental evaluation. If the new issue is not addressed in the GEIS, the NRC staff would determine the significance of the issue and document the analysis in the SEIS.

1.6 Decisions to be Supported by the SEIS

The decision to be supported by the SEIS is whether to renew the operating licenses for Byron for an additional 20 years. The NRC decision standard is specified in 10 CFR 51.103(a)(5):

> In making a final decision on a license renewal action pursuant to Part 54 of this chapter, the 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 decisionmakers would be unreasonable.

There are many factors that the NRC takes into consideration when deciding whether to renew the operating license of a nuclear power plant. The analyses of environmental impacts evaluated in this GEIS will provide the NRC's decisionmaker (in this case, the Commission) with important environmental information for use in the overall decisionmaking process. There are also decisions outside the regulatory scope of license renewal that cannot be made on the basis of the GEIS analysis. These decisions include the following issues: changes to plant cooling systems, disposition of spent nuclear fuel, emergency preparedness, safeguards and security, need for power, and seismicity and flooding (NRC 2013b).

1.7 Cooperating Agencies

During the scoping process, no Federal, state, or local agencies were identified as cooperating agencies in the preparation of this SEIS.

1.8 Consultations

The Endangered Species Act of 1973, as amended; the Magnuson–Stevens Fisheries Conservation and Management Act of 1996, as amended (MSA); and the National Historic Preservation Act of 1966, as amended (NHPA), require that Federal agencies consult with applicable state and Federal agencies and groups before taking action that may affect endangered species, fisheries, or historic and archaeological resources, respectively. The NRC consulted with the following agencies and groups; Appendix D provides a discussion of the consultation documents:

- U.S. Fish and Wildlife Service (FWS);
- Illinois Historic Preservation Agency;
- Advisory Council on Historic Preservation;
- Ho-Chunk Nation;
- Miami Tribe of Oklahoma;

- Peoria Tribe of Indians of Oklahoma;
- Citizen Potawatomi Nation;
- Sac and Fox Tribe of the Mississippi in Iowa/Meswaki Nation;
- Sac and Fox Nation of Missouri in Kansas and Nebraska;
- Sac and Fox Nation;
- Pokagon Band of Potawatomi;
- Forest County Potawatomi;
- Hannahville Indian Community, Band of Potawatomi;
- Prairie Band Potawatomi Nation;
- Winnebago Tribe of Nebraska;
- Kickapoo Tribe in Kansas; and
- Kickapoo Tribe of Oklahoma.

1.9 Correspondence

During the course of the environmental review, the NRC staff contacted Federal, state, regional, local, and tribal agencies listed in Section 1.8. Appendices C and D contain a chronological list of all documents sent and received during the environmental review. Appendix D lists the correspondence associated with Endangered Species Act of 1973, as amended; the MSA; and the NHPA. Appendix C lists all other correspondence.

1.10 Status of Compliance

Exelon is responsible for complying with all NRC regulations and other applicable Federal, state, and local requirements. Appendix F of the GEIS describes some of the major applicable Federal statutes. There are numerous permits and licenses issued by Federal, state, and local authorities for activities at Byron. Appendix B contains further information about Byron status of compliance.

1.11 Related State and Federal Activities

The NRC reviewed the possibility that activities of other Federal agencies might impact the renewal of the operating license for Byron. There are no Federal projects that would make it necessary for another Federal agency to become a cooperating agency in the preparation of this SEIS.

There are no known American Indian lands within 50 mi (80 km) of Byron. There are two Federally owned facilities within 50 mi of Byron: (1) Fermi National Accelerator Laboratory and (2) Upper Mississippi River Wildlife and Fish Refuge.

The NRC is required under Section 102(2)(C) of NEPA to consult with and obtain the comments from any Federal agency that has jurisdiction by law or special expertise with respect to any environmental impact involved in the subject matter of the EIS. For example, during the course of preparing the SEIS, the NRC consulted with the FWS. A complete list of consultation correspondences is listed in Appendix D.

1.12 References

10 CFR 51. *Code of Federal Regulations*, Title 10, *Energy,* Part 51, "Environmental protection regulations for domestic licensing and related regulatory functions."

10 CFR 54. *Code of Federal Regulations*, Title 10, *Energy,* Part 54, "Requirements for renewal of operating licenses for nuclear power plants."

78 FR 44603. U.S. Nuclear Regulatory Commission. "Byron Nuclear Station, Units 1 and 2, and Braidwood Nuclear Station, Units 1 and 2; Exelon Generation Company, LLC." *Federal Register* 78(142):44603-44606. July 24, 2013.

78 FR 47800. U.S. Nuclear Regulatory Commission. "License Renewal Application for Byron Station, Units 1 and 2; Exelon Generation Company, LLC." *Federal Register* 78(151):47800-47802. August 6, 2013.

[AEA] Atomic Energy Act of 1954, as amended. 42 U.S.C. § 2011 et seq.

Endangered Species Act of 1973, as amended. 16 U.S.C. § 1531 et seq.

[Exelon] Exelon Generation Company, LLC. 2013a. "Applicant's Environmental Report—Operating License Renewal Stage, Byron Station." May 31, 2013. 707 p. Agencywide Documents Access and Management System (ADAMS) No. ML14022A048.

[Exelon] Exelon Generation Company, LLC. 2013b. "License Renewal Application, Byron and Braidwood Stations, Units 1 and 2." June 3, 2013. 3,749 p. ADAMS No. ML131620554.

[MSA] Magnuson–Stevens Fishery Conservation and Management Act, as amended. 16 U.S.C. § 1801 et seq.

[NEPA] National Environmental Policy Act of 1969, as amended. 42 U.S.C. § 4321 et seq.

[NHPA] National Historic Preservation Act of 1966, as amended. 16 U.S.C. § 470 et seq.

[NRC] U.S. Nuclear Regulatory Commission. 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Final Report.* Washington, DC: NRC. NUREG–1437, Volumes 1 and 2. May 31, 1996. 1,204 p. ADAMS Nos. ML040690705 and ML040690738.

[NRC] U.S. Nuclear Regulatory Commission. 1999. Section 6.3—Transportation, Table 9.1, Summary of findings on NEPA issues for license renewal of nuclear power plants. In: *Generic Environmental Impact Statement for License Renewal of Nuclear Plants.* Washington, DC: NRC. NUREG–1437, Volume 1, Addendum 1. August 1999. ADAMS No. ML040690720.

[NRC] U.S. Nuclear Regulatory Commission. 2011. Commission Memorandum and Order: Denying Suspension Petitions, Addressing Additional Requests for Relief, and Granting a Request for a Safety Analysis (CLI-11-05). September 9, 2011. ADAMS No. ML11252A958.

[NRC] U.S. Nuclear Regulatory Commission. 2013a. Memorandum from L. James, Senior Project Manager, to A. Simmons, Acting Chief. Subject: Forthcoming meeting to discuss the license renewal process and environmental scoping for Exelon Generation Company, LLC (Exelon), Byron Nuclear Station, Units 1 and 2. August 7, 2013. ADAMS No. ML13217A069.

[NRC] U.S. Nuclear Regulatory Commission. 2013b. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants. Revision 1*. Washington, DC: NRC. NUREG-1437 Volumes 1, 2, and 3. June 19, 2013. 1,535 p. ADAMS No. ML13107A023.

[NRC] U.S. Nuclear Regulatory Commission. 2013c Letter from L. James, Project Manager, to M. Gallagher, Exelon Generating Company, LLC. Subject: "Summary of the site audit related to the review of the license renewal application for Byron Nuclear Station, Units 1 and 2 (TAC Nos. MF1834 and MF1835)." October 4, 2013. ADAMS No. ML13270A069.

[NRC] U.S. Nuclear Regulatory Commission. 2014. *Environmental Impact Statement Scoping Process Summary Report, Byron Station, Units 1 and 2, Byron, IL*. Rockville, MD: NRC. May 28, 2014. 83 p. ADAMS No. ML14041A334.

2.0 ALTERNATIVES INCLUDING THE PROPOSED ACTION

Although the U.S. Nuclear Regulatory Commission's (NRC's) decisionmaking authority in license renewal is limited to deciding whether or not to renew a nuclear power plant's operating license, the NRC's implementation of the National Environmental Policy Act (NEPA) requires consideration of the environmental impacts of potential alternatives to renewing a plant's operating license. While the ultimate decision about which alternative (or the proposed action) to carry out falls to operator, state, or other non-NRC Federal officials, comparing the impacts of renewing the operating license to the environmental impacts of alternatives allows the NRC to determine whether the environmental impacts of license renewal are so great that preserving the option of license renewal for energy-planning decisionmakers would be unreasonable (10 CFR 51.95(c)(4)).

Energy-planning decisionmakers and owners of the nuclear power plant ultimately decide whether the plant will continue to operate, and economic and environmental considerations play important roles in this decision. In general, the NRC's responsibility is to ensure the safe operation of nuclear power facilities and not to formulate energy policy or encourage or discourage the development of alternative power generation. The NRC does not engage in energy-planning decisions and makes no judgment as to which energy alternatives evaluated would be the most likely alternative in any given case.

The remainder of this chapter provides: (1) a description of the proposed action, (2) a description of alternatives to the proposed action (including the no-action alternative), and (3) alternatives to Byron Station, Units 1 and 2 (Byron) license renewal that were considered and eliminated from detailed study. Chapter 4 of this plant-specific supplemental environmental impact statement (SEIS) compares the impacts of renewing the operating licenses of Byron and continued plant operations to the environmental impacts of alternatives.

2.1 Proposed Action

As stated in Section 1.1 of this document, the NRC's proposed Federal action is the decision of whether to renew the Byron operating licenses for an additional 20 years. For the NRC to determine the impacts from continued operation of Byron, an understanding of that operation is needed. A description of normal power plant operations during the license renewal term is provided in Section 2.1.1. Byron is a two-unit, nuclear-powered steam-electric generating facility that began commercial operation in February 1985 (Unit 1) and January 1987 (Unit 2). The nuclear reactor for each unit is a Westinghouse pressurized-water reactor (PWR), producing 2,370 megawatts electric (MWe) (Exelon 2013a).

2.1.1 Plant Operations During the License Renewal Term

Most plant operation activities during license renewal would be the same as or similar to those occurring during the current license term (NRC 2013a). Section 2.1.1 of the *Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants* (GEIS), NUREG-1437, Revision 1 (NRC 2013a), describes the general types of activities that are carried out during the operation of a nuclear power plant such as Byron, as follows:

- reactor operation;
- waste management;
- security;

- office and clerical work;
- surveillance, monitoring, and maintenance; and
- refueling and other outages.

As stated in the Exelon Generation Company, LLC's (Exelon's) Environmental Report (ER), Byron will continue to operate during the license renewal term in the same manner as during the current license term except for, as appropriate, additional aging management programs to address structure and component aging, in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

2.1.2 Refurbishment and Other Activities Associated With License Renewal

Refurbishment activities include replacement and repair of major systems, structures, and components. Replacement activities include replacement of steam generators for PWRs and recirculation piping systems for boiling-water reactors (BWRs). The major refurbishment class of activities characterized in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (NRC 2013a) is intended to encompass actions that typically take place only once in the life of a nuclear plant, if at all. Examples of these activities include, but are not limited to, replacement of boiling-water reactor recirculation piping and pressurized-water reactor steam generators. These actions may have an impact on the environment beyond those that occur during normal operations and may require evaluation, depending on the type of action and the plant-specific design.

In preparation for its license renewal application, Exelon performed an evaluation of these structures, systems, and components (SSCs) in accordance with 10 CFR 54.21, "Contents of application—technical information," to identify the need to undertake any major refurbishment activities that would be necessary to support the continued operation of Byron, during the proposed 20-year period of extended operation (Exelon 2013a).

As a result of its SSC evaluation, Exelon did not identify the need to undertake any major refurbishment or replacement activities associated with license renewal to support the continued operation of Byron beyond the end of the existing operating license (Exelon 2013a). Therefore, refurbishment activities are not discussed under the proposed action in Chapter 4.

However, Exelon identified two hypothetical refurbishment activities that may occur during the period of continued operation (Exelon 2013a), which will be discussed in Section 4.16, Cumulative Impacts of Proposed Action:

- steam generator replacement for Unit 2, and
- reactor pressure vessel (RPV) head replacement for both or either unit.

Exelon's experience in replacing the steam generators for Unit 1 allowed for a determination that analyses of environmental impacts associated with the hypothetical steam generator replacement would bound the hypothetical RPV head replacement. Specifically, the replacement of the steam generators would require more time (90 days vs. 7 days) and more people (500 vs. 340) than the RPV head replacement. The remaining factors (personnel access, parking and potable water supply, sufficient disturbed land to support onsite laydown facilities, and new storage facility) would be similar for both activities (Exelon 2013a).

As a result of experience and analyses, Exelon chose to analyze the hypothetical replacement of the Unit 2 steam generators (Exelon 2013a). Specific impacts of the hypothetical replacement of Unit 2's steam generators are discussed in Section 4.16, Cumulative Impacts.

2.1.3 Termination of Nuclear Power Plant Operations and Decommissioning After the License Renewal Term

The impacts of decommissioning are described in the *Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities: Regarding the Decommissioning of Nuclear Power Reactors*, NUREG-0586 (NRC 2002). The majority of the activities associated with plant operations would cease with reactor shutdown. Some activities (e.g., security and oversight of spent nuclear fuel) would remain unchanged, while others (waste management, office and clerical work, laboratory analysis, and surveillance, monitoring, and maintenance) would continue at reduced or altered levels. Systems dedicated to reactor operations would cease operations; however, impacts from their physical presence may continue if not removed after reactor shutdown. For sites such as Byron, with more than one unit, shared systems may operate at reduced capacities. Impacts associated with dedicated systems that remain in place or shared systems that continue to operate at normal capacities would remain unchanged.

Decommissioning will occur whether Byron is shut down at the end of its current operating licenses or at the end of the period of extended operation. There are no site-specific issues related to decommissioning. The GEIS concludes that license renewal would have a negligible (SMALL) effect on the impacts of terminating operations and decommissioning on all resources.

2.2 Alternatives

As stated at the beginning of this chapter, the NRC has the obligation to consider reasonable alternatives to the proposed action of renewing the license for a nuclear reactor. A reasonable replacement power alternative must be commercially viable on a scale capable of producing baseload power and must be operational prior to the expiration of the reactor's operating license(s), or expected to become commercially viable or expected to produce baseload power and be operational prior to the expiration of the reactor's operating license(s). The 2013 GEIS update incorporated the latest information on replacement power alternatives; however, rapidly evolving technologies are likely to outpace the information presented in the GEIS. As such, a site-specific analysis of alternatives must be performed for each SEIS, taking into account changes in technology and science since the preparation of the GEIS.

Section 2.2.1 below describes the no-action alternative (i.e., the NRC takes no action and does not issue renewed licenses for Byron). Sections 2.2.2.1–2.2.2.5 describe the characteristics of replacement power alternatives for Byron.

2.2.1 No-Action Alternative

At some point, operating nuclear power plants will terminate operations and undergo decommissioning. The no-action alternative represents a decision by the NRC not to renew the operating license of a nuclear power plant beyond the current operating license term. Under the no-action alternative, the NRC does not renew the operating licenses, and the Byron plant shuts down at or before the end of the current licenses, in 2024 and 2026. After shutdown, plant operators will initiate decommissioning in accordance with 10 CFR 50.82.

Only those impacts that arise directly as a result of plant shutdown will be addressed in this SEIS. The environmental impacts from decommissioning and related activities are addressed in several other documents, including the *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities*, NUREG-0586, Supplement 1 (NRC 2002); the license renewal GEIS, Chapter 4 (NRC 2013a); and Chapter 4 of this SEIS. These analyses either directly address or bound the environmental impacts of decommissioning whenever Exelon ceases to operate Byron.

Even with renewed operating licenses, Byron will eventually shut down, and the environmental impacts addressed later in Chapter 4 of this SEIS will occur at that time. As with decommissioning impacts, shutdown impacts are expected to be similar whether they occur at the end of the current license or at the end of a renewed license.

Termination of operations at Byron would result in the total cessation of electrical power production. Unlike the alternatives described below in Section 2.2.2, no-action does not expressly meet the purpose and need of the proposed action as described in Section 1.2, as it does not provide a means of delivering baseload power to meet future electric system needs. Assuming that a need currently exists for the power generated by Byron, the no-action alternative would likely create a need for a replacement power alternative. A full range of replacement power alternatives (including fossil fuels, new nuclear, and renewable energy sources) are described in the following section, and their potential impacts are assessed in Chapter 4. Although the NRC's authority only extends to the decision of whether to renew the Byron operating licenses, the replacement power alternatives described in the following sections represent possible options for energy-planning decisionmakers should the NRC choose not to renew the Byron operating licenses.

2.2.2 Replacement Power Alternatives

In evaluating alternatives to license renewal, the NRC considered energy technologies or options currently in commercial operation, as well as technologies not currently in commercial operation but likely to be commercially available by the time the current Byron operating licenses expire. The current operating licenses for the Byron Units 1 and 2 expire on October 31, 2024, and November 6, 2026, respectively. Alternatives that cannot be constructed, permitted, and connected to the grid by the time Byron licenses expire were eliminated from detailed consideration.

Alternatives that cannot provide the equivalent of Byron's current generating capacity and, in some cases, those alternatives whose costs or benefits do not justify inclusion in the range of reasonable alternatives, were eliminated from detailed consideration. Each alternative eliminated from detailed study is briefly discussed, and a basis for its removal is provided at the end of this section. In total, 17 alternatives to the proposed action were considered (see text box) and then narrowed to the 5 alternatives considered in Sections 2.2.2.1–2.2.2.5. The NRC staff evaluated the environmental impacts of these five alternatives and the no-action alternative and discusses them in depth in Chapter 4 of this SEIS.

The GEIS presents an overview of some energy technologies but does not reach any conclusions about which alternatives are most appropriate. Because many energy technologies are continually evolving in capability and cost, and because regulatory structures have changed to either promote or impede development of particular alternatives, the analyses in this chapter may include updated information from the following sources:

- Energy Information Administration (EIA),
- other offices within the U.S. Department of Energy (DOE),
- U.S. Environmental Protection Agency (EPA),
- industry sources and publications, and
- information submitted by Exelon in its ER.

Alternatives Evaluated in Depth:

- new nuclear
- coal-integrated gasification combined cycle
- natural gas combined cycle
- combination alternative (wind power, natural gas combined cycle, and solar power)
- purchased power

Other Alternatives Considered:

- energy efficiency and conservation
- wind power
- solar power
- hydroelectric power
- wave and ocean energy
- geothermal power
- municipal solid waste
- biomass
- oil-fired power
- fuel cells
- delayed retirement

The evaluation of each alternative in Chapter 4 of this SEIS considers the environmental impacts across several impact categories: land use and visual resources, air quality and noise, geologic environment, water resources, ecological resources, historic and cultural resources, socioeconomics, human health, environmental justice, and waste management. Most site-specific issues (Category 2) have been assigned a significance level of SMALL, MODERATE, or LARGE. For ecological and historic and archaeological resources, the impact significance determination language is specific to the authorizing legislation (e.g., Endangered Species Act and National Historic Preservation Act). The order of presentation of the alternatives is not meant to imply increasing or decreasing level of impact. Nor does it imply that an energy-planning decisionmaker would be more likely to select any given alternative.

To ensure that the alternatives analysis is consistent with state or regional energy policies, the NRC reviewed energy-related statutes, regulations, and policies within the Byron region. As a result, the staff considers alternatives that include wind power or solar photovoltaic (PV) power, as well as a combination that includes both of them.

Region of Influence

Byron is owned and operated by Exelon and provides electricity through Commonwealth Edison (ComEd) (Exelon 2013a). ComEd operates under the PJM Interconnection, a regional transmission organization that coordinates the movement of wholesale electricity in 13 states across the Midwest and Northeast (Exelon 2013a). ComEd provides service to 3.8 million customers across northern Illinois. Its service territory borders Iroquois County to the south, the Wisconsin border to the north, the Iowa border to the west, and the Indiana border to the east (ComEd 2013). However, electricity consumption in Illinois is not limited to electricity that is generated within the State. Although northern Illinois relies on electricity from ComEd, the rest of Illinois and surrounding states, which are not part of the PJM Interconnection, are part of the Midcontinent Independent System Operator (MISO) (See Figure 2–1) (Exelon 2013a).

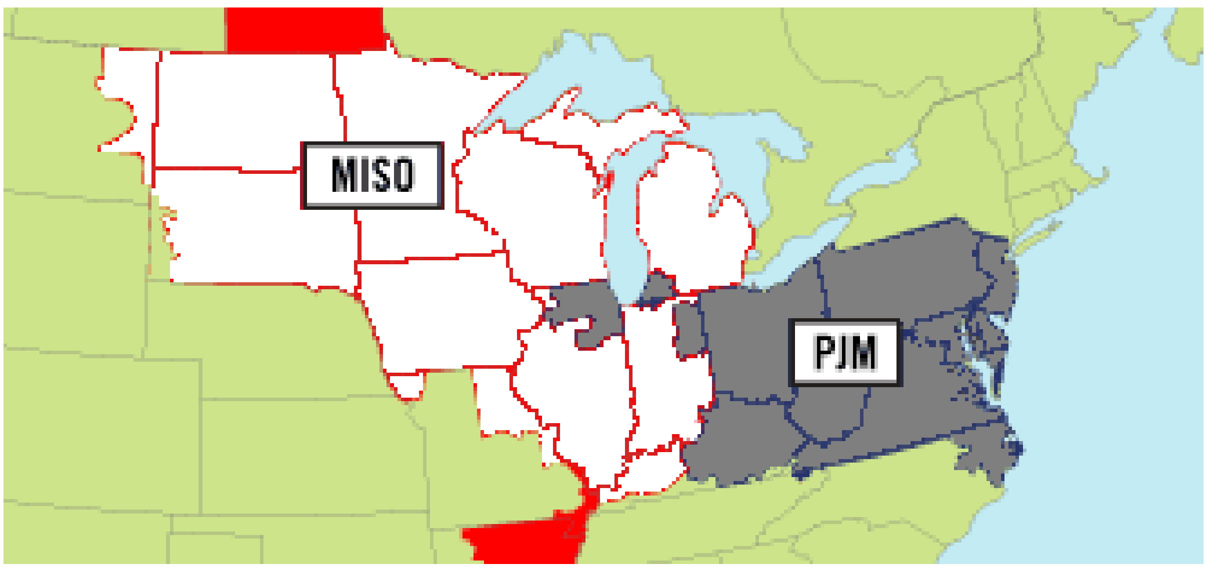
If renewed licenses were not issued, replacement power for Byron would be required in northern Illinois. Electricity could be replaced by generation sources from a variety of locations. Electricity could be transported from within the PJM Interconnection; however, the PJM Interconnection in Illinois is geographically distant from the rest of the PJM region (see Figure 2–1). It is also possible that electricity within MISO could be purchased by PJM, and efforts are currently being made to increase coordination and deliverability between the regional transmission organizations (Ott 2013b). In addition, the State of Illinois has a renewable portfolio standard that includes a geographic eligibility requirement stipulating that eligible renewable resources must be procured from facilities located in Illinois or states that adjoin Illinois (Wisconsin, Indiana, Iowa, Kentucky, Michigan, and Missouri) (ILGA 2011). Renewable resources can be obtained only from other regions of the country if they are not available in Illinois or in adjoining states (ILGA 2011).

Therefore, because replacement power would be required in northern Illinois and any renewable energy resources would need to be procured from adjoining states, the NRC staff evaluated the impacts of locating replacement power facilities within the States of Illinois, Indiana, Iowa, Kentucky, Michigan, Missouri, and Wisconsin. These seven states constitute the region of influence (ROI) for the NRC staff's analysis of alternatives. The NRC assumes that replacement power would either be produced in northern Illinois within the PJM region or would be purchased by PJM from MISO.

In 2012, electric generators in the ROI had a net summer generating capacity of approximately 179,000 megawatts (MW). This capacity included units fueled by coal (49 percent), natural gas (27 percent), nuclear (11 percent), and wind (6.6 percent) (EIA 2014c).

In 2011, the electric industry in the ROI provided approximately 744 million megawatt hours (MWh) of electricity. Electricity produced in the ROI was dominated by coal (67 percent) and nuclear (21 percent). While natural gas makes up nearly 30 percent of the installed generating capacity in the ROI, it provides only 6 percent of electricity in the region. Nonhydroelectric renewable energy produced 1.3 percent of the electricity in the ROI (EIA 2014b).

Figure 2–1. Territories of MISO and PJM Interconnection



Source: MISO-PJM undated

Renewable energy legislation in the Region of Influence

Renewable energy legislation in Illinois allows the purchase of electricity generation in adjoining states; therefore, any legislation targeting renewable energy in these states could impact a state's incentive to develop renewable resources. Five States in the ROI (Illinois, Iowa, Missouri, Wisconsin, and Michigan) have legally mandated renewable energy legislation. The State of Indiana has a voluntary program, and State of Kentucky does not have any renewable energy requirements. The paragraphs below briefly outline each state's program, including renewable energy goals and benchmarks.

In August 2007, Illinois adopted a renewable portfolio standard that requires the State's utilities to produce at least 25 percent of their power from renewable sources by 2025, 75 percent of which must come from wind. Solar photovoltaics must comprise 6 percent of the annual requirement for calendar year 2015 and thereafter. Other eligible sources include biomass and existing hydroelectric power (DSIRE 2012a). The law also includes an energy efficiency standard that requires utilities to implement cost-effective energy efficiency measures to meet energy savings of 2 percent by calendar year 2015 and thereafter (ILGA 2011). For electric utilities (including ComEd), eligible resources must be located in Illinois; resources can be purchased from adjoining states only if there are insufficient instate resources (ILGA 2011).

Iowa's Alternative Energy Production Law requires the State's two investor-owned utilities to generate a combined total of 105 megawatts (MW) of their generating capacity from renewable energy sources. A 2007 order allows the utilities to participate in renewable energy credit trading programs by distinguishing between renewable electricity production capacity used to comply with Iowa law and that which can be used to satisfy other states' renewable portfolio standards (DSIRE 2012b).

Missouri adopted a renewable portfolio standard that requires investor-owned utilities to increase their use of renewable sources by 15 percent by 2021 and includes a provision specifying that 2 percent of the renewable portfolio standard requirement must be met by solar energy. Resources can be purchased from outside Missouri, but renewable energy generated in State receives a multiplier of 1.25 compared to out-of-State generation (DSIRE 2013b).

Wisconsin's renewable portfolio standard requires utilities to produce 10 percent of their electricity from renewable sources by 2015. Included in the renewable portfolio standard is a provision that allows electricity providers to create and sell or transfer renewable resource credits and renewable energy certificates. Renewable energy generated outside Wisconsin is eligible, provided that the electricity is distributed to Wisconsin customers (DSIRE 2012c).

Michigan enacted a Renewable Energy Standard in 2008 that requires utilities to generate 10 percent of their retail electricity sales from renewable energy resources by 2015. The standard also allows energy efficiency and advanced cleaner energy systems to meet part of the requirement. Renewable energy credits can be purchased from in-State or out-of-State facilities, provided that the facilities are located within the retail electric service territory of a utility that is recognized by the Michigan Public Service Commission (DSIRE 2013a).

Indiana does not have a mandatory renewable or alternative energy portfolio standard. On July 9, 2012, Indiana adopted a Clean Energy Portfolio Standard, which sets a voluntary goal of 10 percent clean energy by 2025, based on the amount of electricity supplied by the utility in 2010. Unlike many of the other ROI states, up to 30 percent of the goal may be met with clean coal technology, nuclear energy, combined heat and power systems, natural gas that displaces electricity from coal, clean coal technology, and net-metered distributed generation facilities. Fifty percent of qualifying energy must come from within the State (DSIRE 2012d).

Kentucky is the only state in the ROI that does not have mandatory or voluntary renewable energy requirements.

Given known technology and technological and demographic trends, the EIA predicts that 32 percent of electricity in the United States will be generated by coal in 2040 (EIA 2013a). In all the Midwest case projections, coal accounts for 42 percent in 2040 (EIA 2013a). Natural gas generation rose from 16 percent in 2000 to 24 percent in 2011 and is projected to increase to 35 percent in 2040, surpassing coal as the largest share of U.S. electric power generation (EIA 2013a, 2013d). Electricity generation from renewable energy is expected to grow from 13 percent of total generation in 2011 to 16 percent in 2040. However, there are uncertainties that could affect this forecast, particularly the implementation of policies aimed at reducing greenhouse gas emissions which would have a direct effect on fossil fuel based generation technologies (EIA 2013a).

This section describes replacement power alternatives to license renewal. These include a new nuclear alternative in Section 2.2.2.1; a coal-integrated gasification combined cycle (IGCC) alternative in Section 2.2.2.2; a natural gas combined-cycle (NGCC) alternative in Section 2.2.2.3; a combination natural gas, wind, and solar power alternative in Section 2.2.2.4; and a purchased power alternative in Section 2.2.2.5. Table 2–1 summarizes key design characteristics of the alternative technologies evaluated in depth. The environmental impacts of these alternatives are evaluated in Chapter 4.

Table 2–1. Summary of Replacement Power Alternatives and Key Characteristics Considered in Depth

	New Nuclear Alternative	IGCC Alternative	NGCC Alternative	Combination Alternative
Summary of Alternative	Two-unit nuclear plant, each with 1,120 MWe, for a total of 2,240 MWe	Four 618-MWe units, for a total of 2,472 MWe	Five 560-MWe units, for a total of 2,800 MWe	One 360 MWe NGCC unit; a 1,813 MWe wind farm; and a 227 MWe installed solar photovoltaic facility, for a total of 2,400 MWe.
Location	An existing nuclear plant site or retired coal plant site. New transmission line(s) and other infrastructure upgrades may be required. Some facilities (e.g., support buildings, potable water supply, and sanitary discharge structures) could be shared with existing plant.	An existing plant site or retired coal plant site. New transmission line(s) and other infrastructure upgrades may be required. Some facilities (e.g., support buildings, potable water supply, and sanitary discharge structures) could be shared with existing plant.	An existing plant site or retired coal plant site. New transmission line(s) and other infrastructure upgrades may be required; would require construction of a new or upgraded pipeline. Some facilities (e.g., support buildings, potable water supply, and sanitary discharge structures) could be shared with existing plant.	Spread across multiple sites throughout the ROI
Cooling System	Closed-cycle with natural draft cooling towers. Cooling water withdrawal—54 mgd; consumptive water use—40 mgd (NRC 2008).	Closed-cycle with mechanical draft cooling towers. Cooling water withdrawal—25 mgd; consumptive water use—20 mpd (NETL 2013a).	Closed-cycle with mechanical draft cooling towers. Cooling water withdrawal—17 mgd; consumptive water use—13 mgd (NETL 2013a).	For NGCC portion, closed-cycle with mechanical draft cooling towers. Cooling water would be 15% of that required for NGCC alternative. Minimal water use for wind and solar.

	New Nuclear Alternative	IGCC Alternative	NGCC Alternative	Combination Alternative
Land Require-ments	355 ac (144 ha) (NRC 2008); 520 ac (210 ha) for uranium mining and processing [1] (NRC 2013a)	2,000 ac (800 ha) for the major permanent facilities; 1,100 ac (450 ha) per year for mining (DOE 2010a)	94 ac (38 ha) for the plant, including pipelines (Exelon 2013a); 10,080 ac (4,079 ha) for gas extraction and collection (NRC 1996)	Wind farms would require 3,376 ac (1,366 ha) to 10,127 ac (4,098 ha); (WAPA and FWS 2013); solar photovoltaic facilities would require 6,749 ac (2,731 ha) (Ong et al. 2013). For NGCC portion, land use would remain the same at 94 ac (38 ha) (Exelon 2013a).
Work Force	3,500 workers during peak construction; 812 workers during operations (NRC 2008)	4,600 workers during peak construction; 420 workers during operations (DOE 2010a)	1,783 workers during peak construction; 94 workers during operations (Exelon 2013a)	Solar photovoltaic—600 workers during peak construction, 60 workers during operations; for wind—931 workers during construction, 566 workers during operations (DOE 2010b). The number of construction and operations workers would be less than the standalone alternative but would not be a linear reduction because of needing a minimum number of workers regardless of the size of the NGCC plant.

[1] Normalized to model light water reactor annual fuel requirement. 46% of this land requirement is temporarily committed land.

Key: ac = acres; cfs = cubic feet per second; ha = hectares; IGCC = coal-integrated gasification combined cycle; mgd = million gallons per day; MWe = megawatts electric; NGCC = natural gas combined-cycle; ROI = region of influence

Sources: DOE 2010a, 2010b; Exelon 2013a; NETL2013a; NRC 1996, 2008, 2013b; Ong et al. 2013; WAPA and FWS 2013

2.2.2.1 New Nuclear Alternative

In this section, NRC staff describes the new nuclear alternative. NRC staff evaluates the environmental impacts from this alternative in Chapter 4.

The NRC staff considered the construction of a new nuclear plant to be a reasonable alternative to license renewal. For example, nuclear generation currently provides 21 percent of electricity generation in the ROI (EIA 2014b). Twelve nuclear power plants operate in the ROI; six applicants have received renewed licenses and three additional applicants have applied for renewed licenses from the NRC (including Byron) (NRC 2013b). In addition, there is interest in new nuclear power plant development in the region; combined license (COL) applications have been filed for two new nuclear power plants in the ROI. On July 24, 2008, Union Electric Company submitted a COL application for Callaway Plant, Unit 2 (Callaway Unit 2), in Callaway County, Missouri, on the existing Callaway site (AmerenUE 2009). However, that application has since been suspended (NRC 2009b). An application was also filed in September 2008 for Enrico Fermi Atomic Power Plant, Unit 3 (Fermi Unit 3), in Monroe County, Michigan, on the existing Fermi site. The NRC staff published the Final Environmental Impact Statement (EIS) for Fermi 3 in January 2013 (NRC 2013c). Although the State of Indiana does not currently have any nuclear power plants, its voluntary clean energy initiative includes nuclear as an eligible technology (DSIRE 2012b).

The NRC staff determined that there is sufficient time for Exelon to prepare and submit an application, build, and operate two new nuclear units before the Byron licenses expire in October 2024 and November 2026. For example, the NRC staff review of a COL application that references a certified design is at least 30 months, not including hearing time. Noncertified designs would take 48 to 60 months to review (NRC 2009a). The recently licensed Vogtle Electric Generating Plant, Units 3 and 4 (Vogtle Units 3 and 4), anticipates a construction schedule of 6 to 7 years (Southern 2013).

In evaluating the new nuclear alternative, the NRC staff assumed that two new nuclear reactors would be built on an existing nuclear or coal power plant site, allowing for the maximum use of existing ancillary facilities such as support buildings and transmission infrastructure. In 1987, Illinois passed a moratorium preventing the construction of new nuclear power plants within the state. Unless the moratorium is lifted, any new nuclear alternative would have to be located elsewhere in the ROI. For the purposes of this analysis, the NRC relied on the Vogtle Units 3 and 4 COL EIS for technological parameters for the new nuclear alternative, because the Vogtle Units 3 and 4 COL considers two new nuclear reactor units with similar output as Byron and is representative of the reactors that could be constructed in the ROI before Byron's licenses expire (NRC 2011). As such, the NRC staff assumed two Westinghouse AP1000 reactors with a net electrical output of 2,240 MWe would replace Byron's current reactors for this alternative. The NRC staff estimated that 324 acres (ac) (131 hectares (ha)) of additional land would be required on a long-term basis because of permanent facilities, and an additional 31 ac (12.5 ha) would be disturbed for temporary facilities, a laydown area, and storage of dredge material (NRC 2008).

The heat rejection demands of a new nuclear alternative would be similar to those of Byron. The new reactors may require a new cooling system (including natural draft cooling towers and intake and discharge structures). The NRC staff assumes that water requirements for the new nuclear alternative would be similar to current water use at Byron. The existing transmission lines leaving the site, as well as construction and drinking water wells are expected to serve the replacement reactor with few modifications required. A new onsite transmission line may be required if insufficient transmission occurs on the site. Construction materials would be delivered by a combination of rail spur, truck, and barge, depending on the specific site location.

It is possible that modifications would be required to deliver such materials, depending on the existing infrastructure at the site; modifications could include new rail lines or access roads.

The NRC staff also considered the installation of multiple small modular reactors as an alternative to renewing the Byron licenses. The NRC established the Advanced Reactor Program in the Office of New Reactors because of considerable interest in small modular reactors along with anticipated license applications by vendors. Small modular reactors are approximately 300 megawatts (MW) or less, would have lower initial capacity than large-scale units, and would have siting flexibility for locations that are not large enough to accommodate traditional nuclear reactors (DOE undated b). As of January 2014, no applications for small modular reactors have been submitted to the NRC. The DOE has estimated that the technology may achieve commercial operation by 2021 to 2025 (DOE undated b). Because small modular reactors are not expected to be operational at a commercial scale until near the time Byron's licenses expire, it is unlikely that eight new small modular reactors (the number of units required to replace Byron's current output) could be constructed in the ROI; therefore, this analysis focuses on nuclear generation by larger nuclear units.

2.2.2.2 IGCC Alternative

In this section, the NRC staff describes the IGCC alternative. The NRC staff evaluates the environmental impacts from this alternative in Chapter 4.

Coal provides the greatest share of electrical power in the ROI, and in 2010, coal represented 49 percent of installed generation capacity and accounted for 67 percent of all electricity generated in the ROI (EIA 2014b). IGCC is a technology that generates electricity from coal and combines modern coal gasification technology with both gas-turbine and steam-turbine power generation. The technology is cleaner than conventional pulverized coal plants because major pollutants are removed from the gas stream before combustion. An IGCC power plant consists of coal gasification and combined-cycle power generation. Coal gasifiers convert coal into a gas (synthesis gas, also referred to as syngas) which fuels the combined-cycle power generating units. The combined-cycle system for a 618-MWe IGCC power plant includes two combustion turbines, two heat recovery steam generators, and a steam turbine. The combined-cycle units combust gas in one or more combustion turbines, and the resulting hot exhaust gas is then used to heat water into steam to drive a steam turbine. The steam turbine then uses the heat from the gas turbine's exhaust through a heat recovery steam generator to produce additional electricity (DOE 2010a). This two-cycle process has a high rate of efficiency, since the exhaust heat that would otherwise be lost is captured and reused. In addition, the power plant would reduce sulfur dioxide, nitrogen oxides, mercury, and particulate emissions by removing constituents from the syngas before combustion. Nearly 100 percent of the nitrogen from the syngas would be removed prior to combustion in the gas turbines and would result in lower nitrogen oxide emissions compared to conventional coal-fired power plants (DOE 2010a).

IGCC power plants have been in operation since the mid-1990s; the Wabash Rice IGCC repowering project in Indiana and the Polk Power Station in Florida are two examples of operating IGCC plants. Recently, there has been an increased interest in new IGCC projects, and multiple new projects have been proposed or have recently begun operations in the United States. The Duke Energy Edwardsport Generation Station in Indiana is a 618-MWe IGCC power plant in the ROI that began commercial operation in June 2013. Duke Energy estimates that the IGCC plant will produce 10 times as much power as the retired coal plant it replaced with 70 percent fewer emissions of sulfur dioxide, nitrogen oxides, and particulates. The IGCC plant will reduce carbon emissions per MWh by nearly half (Duke Energy 2013). In addition, the Edwardsport Generation Station has potential for carbon capture and geologic sequestration. Space has been reserved at the site for carbon dioxide capture equipment (NETL 2013b).

Many IGCC power plants have been designed with carbon capture and storage (CCS) to further reduce carbon dioxide emissions. The Kemper County IGCC project in east-central Mississippi proposes to use CCS to reduce carbon dioxide emissions by almost 70 percent by removing carbon from the syngas post-gasification (DOE 2010a). According to a 2013 National Energy Technology Laboratory (NETL) report, nine IGCC projects totaling over 4,000 MW are currently active; these projects are in the planning stages, or they have begun construction. Thirteen projects have been proposed and subsequently cancelled for a variety of reasons, including air quality issues, state laws and regulations, redirected focus on gas-fired generation and renewables, and unanticipated rising costs (NETL 2013c).

IGCC technology and proposed projects have experienced a number of setbacks and opposition, hindering IGCC's ability to fully integrate into the energy market. The most significant roadblock is IGCC's high capital cost compared to conventional coal-fired power plants. Cost overruns have been experienced at both the Edwardsport IGCC project and the Kemper County IGCC project. FutureGen, an IGCC plant featuring CCS, lost DOE financial support because of escalating cost estimates (Reuters 2012). Other issues include:

- construction timeline overruns,
- limited track record for reliable performance, and
- opposition from an environmental perspective (Rosenberg 2004).

Despite some of the current setbacks and concerns associated with IGCC projects, the NRC staff considers IGCC technology to be a reasonable source of baseload power to replace Byron by the time its licenses expire in 2024 and 2026 because of the current regulatory framework and the number of active IGCC plants within the ROI. For example, on January 8, 2014, EPA issued a proposed rule for carbon pollution that would apply to new fossil fuel-fired power plants. The action proposes performance standards for utility boilers and IGCC units based on partial implementation of a CCS system as the best method of emission reduction. The proposed emission limit for these sources is 1,100 lb carbon dioxide per megawatt hour (CO_2/MWh). The proposed rule cites a number of IGCC projects and concludes that the projects are "consistent with the EIA modeling which projects that few, if any, new coal-fired units would be built in this decade and that those that are built would include CCS" (79 FR 1430). If this rule becomes final, any new coal-fired power plants would likely require CCS in order to achieve the 1,100 lb CO_2/MWh emission limit. Therefore, in this section, the NRC staff considers IGCC power plants as an alternative to Byron because the Edwardsport IGCC project in Indiana is currently in operation and the Kemper IGCC project in Mississippi is under construction. The technology parameters for these plants are considered the current state of technology and are used here to describe a hypothetical IGCC power plant located on an existing power plant site within the ROI.

To replace the electricity that Byron generates, the NRC staff considered four IGCC units, each with a net capacity of 618 MWe. Various coal sources are available to coal-fired power plants in the ROI. For the purpose of this evaluation, the NRC staff assumes that the IGCC alternative would burn a sub-bituminous coal, based on the type of coal used in electric plants in Illinois. NRC staff presumes that coal burned in Illinois will be representative of coal that would be burned in an IGCC alternative regardless of where it may be located (EIA 2012). The IGCC units would reduce sulfur dioxide, nitrogen oxides, mercury, and particulate emissions by removing constituents from the syngas. The removal of nearly 100 percent of the nitrogen from the syngas prior to combustion in the gas turbines would result in significantly lower nitrogen oxide emissions compared to conventional coal-fired fired power plants (DOE 2010a). In addition, the units would be designed with the potential to add CCS later. In a CCS, carbon dioxide emissions would be compressed and piped off site where it could be sold for beneficial use or geologic storage. Additional discussion of air quality impacts associated with the IGCC alternative is discussed in Section 4.3.

The IGCC alternative would be located at an existing site (such as an existing power plant site) to maximize availability of infrastructure and reduce other environmental impacts. Depending on the specific site location, there might be a need to construct new intake and discharge facilities and a new cooling system. The IGCC alternative would use about the same amount of water as Byron and a similar amount as the Edwardsport IGCC plant. The NRC staff assumes the cooling system would use a closed-cycle system with mechanical draft cooling towers. This system would withdraw 25 million gallons per day (gpd) (95 million liters per day (Lpd)) of water and consume 20 million gpd (76 million Lpd). Onsite visible structures could include the boilers, exhaust stacks, intake and discharge structures, mechanical draft cooling towers, transmission lines, and an electrical switchyard. Construction materials would be delivered by a combination of rail spur, truck, and barge, depending on the specific site location. Modifications may be required to deliver such materials; modifications could include new rail lines or access roads.

The NRC staff also considered supercritical pulverized coal (SCPC) as an alternative to renewing the Byron licenses. SCPC was dismissed as the coal alternative because of new regulations aimed at limiting the environmental impacts from conventional pulverized coal plants. The presence of active IGCC plants in the ROI also contributed to the selection of IGCC for analysis.

2.2.2.3 NGCC Alternative

In this section, the NRC staff describes the NGCC alternative. The NRC staff evaluates the environmental impacts from this alternative in Chapter 4.

Natural gas represents nearly 30 percent of installed generation capacity in the ROI, but provides only 6 percent of all electrical power in the ROI (EIA 2014b and 2014c). Nationwide, the percentage of power generated by natural gas is expected to rise by 2040, although the actual rise in natural gas generation will depend on future natural gas prices (EIA 2013a). The NRC staff considers the construction of an NGCC power plant to be a reasonable alternative to license renewal because it is a feasible, commercially available option for providing electrical generating capacity beyond the expiration of Byron's current licenses.

Baseload NGCC power plants have proven their reliability and can have capacity factors as high as 85 percent. In an NGCC system, electricity is generated using a gas turbine that burns natural gas. A steam turbine uses the heat from gas turbine exhaust through a heat recovery steam generator to produce additional electricity. This two-cycle process has a high rate of efficiency since the exhaust heat that would otherwise be lost is captured and reused. Like other fossil fuel sources, NGCC power plants are a source of greenhouse gases, including carbon dioxide. An NGCC power plant, however, produces significantly fewer greenhouse gases per unit of electrical output than conventional coal-powered plants.

To replace the electricity that Byron generates, the NRC staff considered five NGCC units, each with a net capacity of 560 MWe (NETL 2007). The NRC staff assumes that each plant configuration consists of two combustion turbine generators, two heat recovery steam generators, and one steam turbine generator with mechanical draft cooling towers for heat rejection. The power plant is assumed to incorporate a selective catalytic reduction (SCR) system to minimize the plant's nitrogen oxide emissions (NETL 2007).

This 2,800-MWe NGCC plant would consume 124 billion cubic feet (ft^3) (3,500 million cubic meters (m^3)) of natural gas annually, assuming an average heat content of 1,021 British thermal units per cubic foot (BTU/ft^3) (EIA 2013c). Natural gas would be extracted from the ground through wells, then treated to remove impurities and blended to meet pipeline gas standards before being piped through the State pipeline system to the plant site. This NGCC alternative would produce relatively little waste, primarily in the form of spent catalysts used for control of nitrogen oxide emissions.

The NGCC alternative would be located at an existing power plant site to maximize availability of infrastructure and reduce other environmental impacts. Depending on the specific site location, there might be a need to construct new intake and discharge facilities and a new cooling system. Because NGCC power plants generate much of their power from a gas-turbine combined-cycle plant, and the overall thermal efficiency of this type of plant is high, an NGCC alternative would require less cooling water than Byron would. This system would withdraw 17 million gallons per day (gpd) (64 million litres per day (Lpd)) of water and consume 13 million gpd (49 Lpd). The NRC staff assumes the cooling system would use a closed-cycle system with mechanical draft cooling towers. Onsite visible structures could include the cooling towers, exhaust stacks, intake and discharge structures, transmission lines, natural gas pipelines, and an electrical switchyard. Construction materials would be delivered by a combination of rail spur, truck, and barge, depending on the specific site location. Modifications may be required to deliver such materials; modifications could include new rail lines or access roads.

2.2.2.4 Combination Alternative (NGCC, Wind, Solar)

In this section, NRC staff describes the environmental impacts of a combination alternative to the continued operation of Byron, consisting of an NGCC facility constructed at an existing power plant site, operating in conjunction with land-based wind farms as well as solar energy facilities, all of which would be located within the ROI. The NRC staff evaluates the environmental impacts from this alternative in Chapter 4.

To serve as an effective baseload power alternative to the Byron reactors, this combination alternative must be capable of providing an equivalent amount of baseload power. For the purpose of this evaluation, the NRC staff presumes that NGCC, wind farms, and solar photovoltaic facilities would comprise the combination alternative.

<u>NGCC Portion of the Combination Alternative</u>

To produce its required share of power, the NGCC portion, operating at an expected capacity factor of 85 percent (NETL 2007), would need to have a nameplate rating of approximately 425 MWe.

In 2013, the EIA reported that natural gas-fired power plants are generally used infrequently for shorter periods to meet peak demand. Capacity factors for natural gas plants averaged less than 5 percent during off-peak demand hours for most regions of the country. Natural gas is used for these “peaker plants” because natural gas combustion turbines can respond quickly, so they tend to be used to meet short-term increases in electricity demand (EIA 2013d). A report prepared by CITI Research stated that gas-fired power plants can help overcome the intermittent nature of renewable energy (Channell et al. 2012). The peaking aspect of natural gas-fired power plants makes natural gas an ideal addition to an otherwise renewable energy combination alternative.

NRC staff assumed that one new NGCC unit of the type described in Section 2.2.2.3 would be constructed and installed at an existing power plant site with a total net capacity of 360 MWe. The appearance of an NGCC unit would be similar to that of the full NGCC alternative considered in Section 2.2.2.3, although only one unit would be constructed. The NRC staff assumes that the NGCC portion of this alternative, which is assumed to be located at an existing power plant site, would utilize existing electrical switchyards, substations, and transmission lines. Depending on the existing site conditions, it is possible that intake and discharge structures of the existing cooling system could continue in service, but would be connected to a new closed-cycle cooling system. For the purposes of this analysis, the NRC staff assumes that the NGCC portion of the combination would utilize mechanical draft cooling towers.

Wind Portion of the Combination Alternative

The NRC staff assumes that the wind-generated power from this combination alternative would come from land-based wind farms which would be located in the ROI within the states of Illinois, Indiana, Iowa, Kentucky, Michigan, Missouri, or Wisconsin. The wind portion, assuming a capacity factor of 30 percent, would require a nameplate capacity of 6,042 MWe (WAPA and FWS 2013).

The American Wind Energy Association (AWEA) reports a total of more than 60,000 MW of installed wind energy capacity nationwide as of March 31, 2013 (AWEA 2013). As of March 2013, Texas is by far the leader in installed land-based capacity with 12,214 MW. Two states in the ROI have the third- and fourth-largest installed capacity: Iowa with 5,133 MW, followed by Illinois with 3,568 MW (AWEA 2013). The installed wind capacity in the ROI has been increasing annually by 1,000 MWe to 2,500 MWe in each of the past 6 years, for a total of over 11,000 MWe of additional wind capacity from 2007 to 2012 (DOE 2013a). Therefore, NRC staff considers 6,042 MW of wind energy to be a reasonable amount by the time the Byron licenses expire in 2024 and 2026. As is the case with other renewable energy sources, the feasibility of wind resources serving as alternative baseload power is dependent on the location (relative to expected load centers), value, accessibility, and constancy of the resource. Wind energy must be converted to electricity at or near the point where it is extracted, and there are limited energy storage opportunities available to overcome the intermittency and variability of wind resources. At the current stage of wind energy technology development, wind resources in wind power class 3 and higher are suitable for most utility scale applications (NREL 2014). Wind power class 3 is defined as having a wind speed of 15.7 miles per hour (mph) (7.0 meters per second (m/s)) and a wind density of 500 watts per square meter (W/m^2) at 164 ft (50 m) (NREL 2014). Individual wind turbine capacity increased from 0.71 MW in 1999 to 1.79 MW in 2010. The size of turbine most frequently installed in the United States in recent years is the 1.5-MW turbine (WAPA and FWS 2013). For the purposes of this analysis, the NRC staff assumes wind turbines with a capacity of 1.79 MW. The capacity factors of land-based wind farms are lower than offshore wind farms (WAPA and FWS 2013). For the wind portion of the combination alternative, the NRC staff assumed a capacity factor of 30 percent, resulting in an estimated total net capacity of 1,813 MWe. Wind turbines must be well-separated from each other to avoid interferences to wind flowing through the wind farm, resulting in wind farms requiring substantial amounts of land. Wind turbines may require as much as 1 to 3 ac (0.4 to 1.2 ha) of land for each turbine (WAPA and FWS 2013). Based on the size of the turbines and amount of land required between each turbine, approximately 3,376 turbines and 3,376 to 10,127 ac (1,366 to 4,098 ha) would be required for the wind portion of the combination alternative.

Wind energy’s intermittency affects its viability and value as a baseload power source. However, the variability of wind-generated electricity can be lessened if the proposed wind farms were located at a large distance from one another and allowed to operate as interconnected wind farms, an aggregate controlled from a central point. Distance separation ensures that the two wind farms will not simultaneously experience the same climate, and power will likely be produced at some of the wind farms at any given time (Archer and Jacobson 2007).

Solar Photovoltaic Portion of the Combination Alternative

The solar portion of the combination alternative would be generated through one or more solar photovoltaic energy facilities located in the ROI. Assuming a capacity factor of 19 percent, the solar energy facilities would need a collective nameplate rating of 1,193 MWe. Solar photovoltaic technologies could be installed on building roofs at existing residential, commercial, or industrial sites or at larger standalone solar facilities.

Nationwide, growth in large solar photovoltaic facilities (greater than 5 MW) has resulted in an increase from 70 MW in 2009 to over 700 MW installed capacity in 2011. As of January 2012, it is estimated that more than 11,000 MW of large solar photovoltaic projects have signed power purchase agreements (Mendelsohn et al. 2012). Over 9,000 MW of those solar projects are 50 MW or greater, although most are located in the southwestern United States (Mendelsohn et al. 2012). As described in Section 2.2.2, two States in the ROI (Missouri and Illinois) have renewable energy legislation that includes requirements for solar photovoltaic technology. Missouri's renewable portfolio standard includes a provision specifying that 2 percent of the renewable portfolio standard requirement must be met by solar energy by 2021. Illinois' renewable portfolio standard specifies that solar photovoltaic must comprise 6 percent of the annual requirement for the year 2015-2016 and thereafter. As of 2010, only 9 MW of solar energy capacity had been installed in the ROI.

Solar photovoltaic resources in the ROI range from 4.0 to 5.0 kilowatt hours per square meter per day (kWh/m^2/day). The most viable solar resources are located in Missouri, Iowa, and southern Illinois and Indiana (NREL 2013c). Economically viable solar resources are considered to be 6.75 kWh/m^2/day and greater (BLM and DOE 2010). As is the case with wind energy sources, the feasibility of solar energy resources serving as alternative baseload power is dependent on the location, value, accessibility, and constancy of the resource. Solar photovoltaic uses solar panels to convert solar radiation into usable electricity. Solar cells are formed into solar panels by solar manufacturers that can then be linked into photovoltaic arrays to generate electricity. The electricity generated can be stored, used directly, fed into a large electricity grid, or combined with other electricity generators as a hybrid plant. Solar photovoltaics can generate electricity whenever there is sunlight, regardless of whether or not the sun is directly shining on solar panels. Therefore, solar photovoltaic technologies do not need to directly face and track the sun, which has allowed solar photovoltaic systems to have broader geographical use than concentrated solar power (Ardani and Margolis 2011). Because the ROI contains average solar photovoltaic resources and solar photovoltaics is a commercially available option for providing electrical generating capacity, the NRC staff considers the construction of solar photovoltaic facilities to be a reasonable alternative to license renewal when combined with wind and NGCC.

For the purposes of this analysis, the NRC staff assumes solar photovoltaic facilities with a capacity factor of 19 percent (Ardani and Margolis 2011). Solar photovoltaic facilities may require 6.2 ac (2.5 ha)/MW of land (NRC 2013a). Although not all of this land would be cleared of vegetation and permanently impacted, it represents the land enclosed in the total site boundary of the solar facility (Ong et al. 2013). For the solar portion of this combination alternative, approximately 7,397 ac (2,993 ha) would be required to support an installed net capacity of 227 MWe. In this analysis, the NRC staff does not speculate on the number and size of individual solar facilities, nor their locations within the ROI. However, as stated above, some of the output could be realized by solar photovoltaic installations on building roofs at existing residential, commercial, or industrial sites or at larger standalone solar facilities. To the extent that rooftop or building-integrated solar photovoltaic installations remain popular, land impacts would be relatively minor. Solar photovoltaic systems do not require water for cooling purposes, but a small amount of water is needed to clean the panels and for potable water for the workforce. Impacts identified in the BLM and DOE's Solar Energy Programmatic Environmental Impact Statement (PEIS) (BLM and DOE 2010, 2012), among other technical reports, provide information used in the analyses presented in the impact sections in Chapter 4.

2.2.2.5 Purchased Power Alternative

In this section, the NRC staff describes purchased power as an alternative to the continued operation of Byron.

The impacts from purchased power would depend substantially on the generation technologies used to supply the purchased power. Impacts from operation of other electricity generators would likely occur in the ROI. As discussed in Section 2.2.1, replacement power for Byron would be required in northern Illinois and could come from anywhere within Illinois or adjoining states in either the PJM or MISO Regional Transmission Organizations (RTOs). Given the large geographic area, multiple RTOs within the ROI, and wide-ranging generating facilities, the NRC staff considers purchased power to be a feasible source of baseload power to replace Byron by the time the licenses expire in 2024 and 2026.

Purchased power would likely come from the most common types of electricity generation within the ROI: coal, natural gas, nuclear, and wind. All of these power sources are discussed as alternatives to license renewal of Byron and are identified in Sections 2.2.2.2 to 2.2.2.4. Construction and operational impacts from these sources of electricity generation are considered in Chapter 4. Unlike the alternatives considered in Chapter 4, however, facilities from which power would be purchased would not likely be constructed solely to replace Byron. Purchased power may, however, require new transmission lines (which may require new construction) and may also rely on older and less-efficient power plants operating at higher capacities than they currently operate or new facilities that would be constructed. During operations, impacts from nuclear, coal-fired, and natural gas-fired plants, wind, and solar energy projects would be similar to that described under the new nuclear, coal, natural gas, and combination alternatives described in Chapter 4 for all resource areas. Impacts to air quality from the operations of existing coal and natural gas-fired plants would likely be greater than the operations of new plants because older plants are more likely to be less efficient and without modern emissions controls. Impacts to other resource areas from the operation of existing power plant facilities would likely be less than those for new plants because existing facilities would not require new construction.

2.3 Alternatives Considered but Dismissed

Alternatives to Byron license renewal that were considered and eliminated from detailed study are presented in this section. These alternatives were eliminated because of technical resource availability or current commercial limitations. Many of these limitations would continue to exist when the current Byron licenses expire.

2.3.1 Energy Conservation and Energy Efficiency

Energy conservation can include reducing energy demand through behavioral changes or altering the shape of the electricity load and usually does not require the addition of new generating capacity. Conservation and energy efficiency programs are more broadly referred to as demand-side management (DSM).

Conservation and energy efficiency programs can be initiated by a utility, by transmission operators, by the state, or by other load-serving entities. The State of Illinois' renewable portfolio standard includes an energy efficiency portfolio standard that requires utilities to reduce electric usage by 2 percent of demand by 2015 (DSIRE 2012a), which is equivalent to 4 million MWh, only 20 percent of the amount that would be required to offset Byron's current electrical generation.

In general, residential electricity consumers have been responsible for the majority of peak load reductions, and participation in most programs is voluntary. Therefore, the existence of a program does not guarantee that reductions in electricity demand would occur. The GEIS concludes that while the energy conservation or energy efficiency potential in the United States is substantial, there are likely no cases where an energy efficiency or conservation program has been implemented expressly to replace or offset a large baseload generation station (NRC 2013a). While significant energy savings are possible in the ROI through DSM and energy efficiency programs, conservation and energy efficiency programs are not likely to replace Byron as a standalone alternative, and therefore the NRC staff does not consider conservation and energy efficiency to be a reasonable alternative to license renewal.

2.3.2 Solar

Solar power, including solar photovoltaic and concentrated solar power technologies, produce power generated from sunlight. Photovoltaics convert sunlight directly into electricity using solar cells, made from silicon or cadmium telluride. Concentrating solar power uses heat from the sun to boil water and produce steam to drive a turbine connected to a generator to produce electricity (NREL 2013d). To be considered a viable alternative, a solar alternative must replace the amount of electricity Byron provides. Assuming a capacity factor of 19 percent (Ardani and Margolis 2011), approximately 12,400 MWe of electricity would need to be generated by solar energy facilities in the seven-state ROI.

In 2011, 14 MWh of electricity was generated from solar energy in the ROI (EIA 2014c). DOE's National Renewable Energy Laboratory (NREL) reports that the states in the ROI receive solar insolation of 4.0 to 5.0 kWh/m^2/day, which is considered low to average (NREL 2013c). For utility-scale development, insolation levels below 6.5 kWh/m^2/day are not considered economically viable given current technologies (BLM and DOE 2010). There is more potential for solar development using local photovoltaic applications, such as rooftop solar panels, than through utility-scale solar facilities. In addition, a solar facility can only generate electricity when the sun is shining. Energy storage can be used to overcome intermittency for concentrating solar power facilities; however, current and foreseeable storage technologies that have been paired with solar power facilities have a much smaller capacity than would be necessary to replace Byron. Taking all of the factors above into account, it is unlikely that solar photovoltaic or concentrated solar power technologies could serve as baseload power in the ROI to replace Byron's current electricity output. Given the modest levels of solar energy available throughout the ROI, the lack of substantial installed solar capacity in the ROI and the weather-dependent intermittency of solar power, the NRC staff concludes that a solar power energy facility in the ROI would not be a reasonable alternative to license renewal. The NRC staff evaluated an alternative of solar power in combination with wind and an NGCC plant in Section 2.2.2.4.

2.3.3 Wind

Two states in the ROI have the third- and fourth-largest installed capacity in the Nation: Iowa with 5,133 MW, followed by Illinois with 3,568 MW (AWEA 2013). The installed wind capacity in the ROI has been increasing annually by 1,000 MWe to 2,500 MWe in each of the past 6 years, for a total of over 11,000 MWe of additional wind capacity from 2007 to 2012 (DOE 2013a). All of the wind energy facilities and the electricity generation from wind currently being produced in the ROI are land-based. To be considered a viable alternative, a wind alternative must replace the amount of electricity Byron provides. Assuming a capacity factor of 30 percent for land-based wind and 40 percent for offshore wind, a range of 5,665 to 7,553 MWe of electricity would need to be generated by some combination of land-based and offshore wind energy facilities in the seven-state ROI.

As is the case with other renewable energy sources, the feasibility of wind resources serving as alternative baseload power is dependent on the location (relative to expected load centers), value, accessibility, and constancy of the resource. Wind energy must be converted to electricity at or near the point where it is extracted, and there are limited energy storage opportunities available to overcome the intermittency and variability of wind resource availability. Although wind power is intermittent and individual facilities are unable to provide baseload power, it has been proposed that multiple interconnected wind installations separated by long distances could function as a virtual power plant and provide baseload power since individual facilities would be exposed to different weather and wind conditions. To date, however, no states or utilities operate arrays of wind installations as virtual power plants.

Given the amount of wind capacity necessary to replace Byron and the intermittency of wind power, the NRC staff finds a completely wind-based alternative to be unreasonable. However, the NRC staff also concludes that, when used in combination with other technologies with inherently higher capacity factors, wind energy can provide a viable alternative. The NRC staff evaluated such a possible combination as described in Section 2.2.2.4.

2.3.3.1 Offshore Wind

The United States does not have any offshore wind farms in operation; however, approximately 20 projects representing more than 2,000 MW of capacity are in the planning and permitting process as of 2010 (Musial and Ram 2010). Offshore wind projects have been developed in Europe, most of which are located close to shore and in shallow water less than 98.4 ft (30 m) in depth. Total worldwide installed capacity has been estimated at 2,377 MW (Musial and Ram 2010).

While wind data suggest there is potential for offshore wind farms in the Great Lakes, project costs likely will limit the future potential of large-scale projects (Tidball et al. 2010). NREL (Tidball et al. 2010) estimated that offshore project costs would run approximately 200 to 300 percent higher than land-based systems. In addition, based on current prices for wind turbines, the 20-year levelized cost of electricity produced from an offshore wind farm would be above the current production costs from existing power generation facilities. In addition to cost, other barriers include the immature status of the technology, limited resource area, and high risks and uncertainty (Tidball et al. 2010). As no offshore wind capacity yet exists in either the Great Lakes or on the Atlantic Coast and as none appears likely to exist on a large commercial scale in the Great Lakes by 2024 (given the current state of development), the NRC staff finds that offshore wind will not be a reasonable alternative to Byron.

2.3.3.2 Wind Power with Storage

Energy storage is one possible way to overcome intermittency. Besides pumped hydroelectric facilities, compressed air energy storage (CAES) is the technology most suited for storage of large amounts of energy. In CAES systems, electricity generated during low-demand periods can be stored by using a compressor to pressurize and store air, and during high-demand periods, the compressed air can be used to drive a turbine to generate electricity. A 2011 DOE report analyzed various power generation sources, including wind, coupled with CAES systems

(Ilic et al. 2011). The report considered siting criteria, using (1) proximity to natural gas lines, high voltage transmission, and a market for wholesale electric power and (2) availability of geology and wind resources. The results show that within the ROI there is potential for one CAES site in northwestern Iowa. Without detailed wind-speed data, specific site information, and detailed information on the energy-storage capacity of the potential CAES site, it is difficult to estimate how much wind capacity would be necessary and whether or not it could provide for an all-wind alternative. Furthermore, the NRC staff is not aware of a CAES project coupled with wind generation that is providing baseload power. Therefore, the NRC staff concludes that the use of CAES in combination with wind turbines to replace the Byron power plant is unlikely.

2.3.3.3 Conclusion

Despite the relatively high reliability demonstrated by modern turbines, the recent technological advancements in turbine design and wind farm operation, and wind energy's dramatic market penetrations of recent years, empirical data on wind farm capacity factors and wind energy's limited ability to store power for delayed production of electricity cause the NRC staff to conclude that wind energy—on shore, off shore, or a combination thereof—could not serve as a discrete alternative to the baseload power supplied by the Byron reactors. However, the NRC staff also concludes that, when used in combination with other technologies with inherently higher capacity factors, wind energy can provide a viable alternative. The NRC staff evaluated such a possible combination as described in Section 2.2.2.4.

2.3.4 Biomass

Biomass resources used for biomass-fired generation include agricultural residues, animal manure, wood wastes from forestry and industry, residues from food and paper industries, municipal green wastes, dedicated energy crop, and methane from landfills (IEA 2007). Using biomass-fired generation for baseload power depends on the geographic distribution, available quantities, constancy of supply, and energy content of biomass resources. For this analysis, the NRC staff assumed that biomass would be combusted for power generation in the electricity sector. Biomass is also used for space heating in residential and commercial buildings and can be converted to a liquid form for use in transportation fuels (Haq undated).

In the GEIS, the NRC staff indicated a wood waste facility could provide baseload power and operate with capacity factors between 70 and 80 percent (NRC 2013a). Although the ROI currently produces electricity from biomass fuels, the plants operating within the ROI generated less than 1 percent of the total power generation in 2011 (EIA 2014c). Based on the relatively low electricity generation currently produced at biomass plants, it is unlikely that these plants, or the construction of several new biomass plants, could increase capacity by adding 2,336 MWe of electricity from biomass-fired generation by the time Byron's licenses expire in 2024 and 2026.

For utility-scale biomass electricity generation, the NRC staff assumes that the technologies used for biomass conversion would be similar to fossil fuel plants including the direct combustion of biomass in a boiler to produce steam (NRC 2013a). Biomass generation is generally more cost-effective when cofired with coal plants (IEA 2007). Biomass-fired generation plants generally are small and can reach capacities of 50 MWe, meaning that more than 40 new facilities would be required before the Byron licenses expire. After reevaluating current technologies, the NRC staff finds biomass-fired alternatives as still unable to reliably replace the Byron capacity. For this reason, the NRC staff does not consider biomass to be a reasonable alternative to Byron license renewal.

2.3.5 Hydroelectric

Hydroelectric power uses the force of water to turn turbines which spin a generator to produce electricity. In a run-of-the-river system, the force of a river current provides the force to create the needed pressure for the turbine. In a storage system, water is accumulated in reservoirs created by dams and is released as needed to generate electricity.

DOE's Idaho National Environmental Engineering Laboratory (INEEL) (now Idaho National Laboratory) completed a comprehensive survey of hydropower resources in 1997. The ROI has hydroelectric generating potential of 1,954 MW, adjusting for environmental, legal, and institutional constraints (Conner et al. 1998). These constraints could include (1) scenic, cultural, historical, and geological values; (2) Federal and state land use; and (3) legal protection issues, such as Wild and Scenic legislation and Threatened or Endangered Fish and Wildlife legislative protection. A separate assessment by DOE of nonpowered dams (dams that do not produce electricity) concluded that there is potential for 4,185 MW of electricity in the ROI (ORNL 2012). These nonpowered dams serve various purposes such as providing water supply to inland navigation.

EIA reported that the states composing the ROI generated 2,262 MW electricity from hydroelectric power in 2012 (EIA 2014b). In order to replace Byron's current output, hydroelectric generation across the ROI would need to double by 2024. Although there is potential for anywhere between 1,954 MW and 4,185 MW of hydroelectric power, it is unlikely that the maximum levels of development would occur across the entire ROI by the time Byron's licenses expire in 2024 and 2026 given that generating capacity of hydroelectric power is projected to continue decreasing through 2040 (EIA 2013b). Given the decrease in projected power generation from hydroelectric facilities, the NRC staff does not consider hydroelectric power to be a reasonable alternative to license renewal.

2.3.6 Wave and Ocean Energy

Waves, currents, and tides are often predictable and reliable, making them attractive candidates for potential renewable energy generation. Four major technologies may be suitable to harness wave energy: terminator devices that range from 500 kW to 2 MW, attenuators, point absorbers, and overtopping devices (BOEM undated). Point absorbers and attenuators use floating buoys to convert wave motion into mechanical energy, driving a generator to produce electricity. Overtopping devices trap a portion of a wave at a higher elevation than the sea surface; waves then enter a tube, compressing air that is used to drive a generator that produces electricity (NRC 2013a). Some designs are undergoing demonstration testing at commercial scales, but none are currently used to provide baseload power (BOEM undated).

The Great Lakes do not experience large tides, and there is limited energy output for wave technologies in the Great Lakes. The Electric Power Resource Institute (EPRI) published a document that assessed ocean wave energy resources in the United States. The Great Lakes were not included in the analysis, suggesting that the resource potential is not great enough to use on a commercial scale (EPRI 2011). Consequently, the limited resource availability and infancy of the technologies in the Great Lakes support the NRC staff's conclusion that wave and ocean energy technologies are not feasible substitutes for Byron.

2.3.7 Fuel Cells

Fuel cells oxidize fuels without combustion and its environmental side effects. Fuel cells use a fuel (e.g., hydrogen) and oxygen to create electricity through an electrochemical process. The only byproducts (depending on fuel characteristics) are heat, water, and carbon dioxide (depending on hydrogen fuel type) (DOE undated a). Hydrogen fuel can come from a variety of hydrocarbon resources. Natural gas is a typical hydrogen source.

Fuel cells are not economically or technologically competitive with other alternatives for electricity generation. EIA projects that fuel cells may cost $6,835 per installed kW (total overnight capital costs, 2010 dollars), which is high compared to other alternative technologies analyzed in this section (EIA 2010). More importantly, fuel cell units are likely to be small in size (approximately 10 MWe). It would be extremely costly to replace the power Byron provides; it would require approximately 230 units and modifications to the existing transmission system. Given the immature status of fuel cell technology and high cost, the NRC staff does not consider fuel cells to be a reasonable alternative to Byron license renewal.

2.3.8 Delayed Retirement

A delayed retirement alternative would consider deferring the retirement of generating facilities in Illinois and its six adjoining states that include MISO and PJM RTOs.

To maintain reliable operations, electric systems must be able to meet peak load requirements. To ensure sufficient capacity, this must also include a planning reserve margin (FERC 2013). The projected MISO reserve margin for 2021 is 18.6 percent, which exceeds the reserve margin requirement of 17.4 percent. However, pending EPA regulations may lead to increased coal plant retirements at a faster pace than projected. In that case, 3,000 MW to 12,600 MW of plant retirements could decrease the projected reserves anywhere from 16.22 to 6.9 percent, well below the reserve margin requirement (MISO 2011).

PJM is facing similar constraints due, in large part, to retirements of coal plants given air quality regulations (Ott 2013a). This indicates an emerging reliability problem potentially affecting major population centers within the PJM region in the near future (Ott 2013a). Because the current generation mix has not resulted in the long-term commitment of generation needed for reliability, generation retirements that have occurred with short notice have created unanticipated reliability problems for PJM (Ott 2013a).

The 2014 Annual Energy Outlook predicts that there will be more coal plant retirements before 2016 than previously predicted. These accelerated retirements are driven by low natural gas prices, slow growth in electricity demand, and the requirements of the Mercury and Air Toxics Standards (MATS) that will require significant reductions in plant emissions (EIA 2014a). Exelon also expects increased generation retirements for a variety of reasons, including increased operating costs for older facilities, increased environmental regulations and competition, and decreased load (Exelon undated). As generators are required to adhere to future regulations, some power plants may opt for early retirement of older units rather than incur the cost for compliance. Exelon has further stated that some of their nuclear fleet may be retired early because of low wholesale energy prices and current energy policy (Bloomberg 2014). Because of the uncertain regulatory environment and concerns expressed by MISO and PJM concerning the retirement pace of coal power plants, the NRC staff does not consider delayed retirement to be a reasonable alternative to Byron license renewal.

2.3.9 Geothermal

Geothermal technologies extract the heat contained in geologic formations to produce steam to drive a conventional steam turbine generator. Facilities producing electricity from geothermal energy have demonstrated capacity factors of 95 percent or greater, making geothermal energy a potential source of baseload electric power. However, the feasibility of geothermal power generation to provide baseload power depends on the regional quality and accessibility of geothermal resources. Utility-scale geothermal energy generation requires geothermal reservoirs with a temperature above 200 °F (93 °C). Utility-scale power plants range from small 300 kilowatts electric (kWe) to 50 MWe and greater (TEEIC undated). Geothermal resources are concentrated in the western United States. Specifically, these resources are found in Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming (USGS 2008). In general, most assessments of geothermal resources have been concentrated on these western states. The DOE has also quantified geothermal resources in Minnesota and Vermont but not in any of the states that compose the ROI (DOE 2013c). Geothermal resources are used in the ROI for heating and cooling purposes, but no electricity is currently being produced from geothermal resources in the ROI (EIA 2014c). Given the low resource potential in the ROI, the NRC staff does not consider geothermal to be a reasonable alternative to license renewal.

2.3.10 Municipal Solid Waste

Energy recovery from municipal solid waste converts nonrecyclable waste materials into usable heat, electricity, or fuel through combustion (EPA 2013b). The three types of combustion technologies include mass burning, modular systems, and refuse-derived fuel systems (EPA 2013a). Mass burning is the method used most frequently in the United States. The heat released from combustion is used to convert water to steam, which is used to drive a turbine generator to produce electricity. Ash is collected and taken to a landfill and particulates are captured through a filtering system (EPA 2013a). As of 2010, approximately 86 waste-to-energy plants are in operation in 25 states, processing more than 28 million tons of waste per year (EPA 2013b). These waste-to-energy plants have an aggregate capacity of 2,720 MWe, and although some plants have expanded to handle additional waste and produce more energy, no new plants have been built in the United States since 1995 (EPA 2013b). The average waste-to-energy plant produces about 50 MWe, with some reaching 77 MWe, and can operate at capacity factors greater than 90 percent (Michaels 2010). Indiana has one waste recovery facility that produces steam; Iowa has one waste-to-energy facility that produces 10 MW of electricity; Michigan has three facilities that produce 89.7 MW of electricity; and Wisconsin has two facilities that generate 32.3 MW of electricity (Michaels 2010). In total, as of 2010, the ROI had a municipal solid waste generating capacity of 132 MW. More than 46 average-sized plants would be necessary to provide the same level of output as Byron, almost doubling the national waste-to-energy generation.

The decision to burn municipal waste to generate energy is usually driven by the need for an alternative to landfills rather than energy considerations. Given the improbability that additional stable supplies of municipal solid waste would be available to support approximately 46 new facilities and that so few existing plants operate in the ROI, the NRC staff does not consider municipal solid waste combustion to be a reasonable alternative to Byron license renewal.

2.3.11 Petroleum

In the ROI, oil-fired generation in 2012 had a generating capacity of 4,986 MW (EIA 2014b).

The variable costs of oil-fired generation tend to be greater than those of the nuclear or coal-fired operations, and oil-fired generation tends to have greater environmental impacts than natural gas-fired generation. The high cost of oil has resulted in a steady decline in its use for electricity generation (EIA 2013a). Given the high cost of oil and the small generating capacity from oil-fired power plants in the ROI, the NRC staff does not consider oil-fired generation a reasonable alternative to Byron license renewal.

2.3.12 SCPC

In general, SCPC power plants are feasible, commercially available options for providing electrical generating capacity. Baseload coal units have proven their reliability and can sustain capacity factors as high as 79 percent. Pulverized coal power generation uses crushed coal that is fed into a boiler where it is burned to create heat. The heat produces steam that is used to spin one or more turbines to generate electricity. Among the technologies available, pulverized coal boilers producing supercritical steam (SCPC boilers) are increasingly common for new coal-fired plants given their high operating temperatures and pressures that increase thermal efficiencies and overall reliability. SCPC facilities consume less fuel per unit output, reducing environmental impacts (NETL undated).

As described in Section 2.2.3, EPA has issued a proposed rule for carbon pollution that would apply to new fossil fuel-fired power plants, including SCPC facilities. The action proposes performance standards and has identified a CCS system as the best method of emission reduction. The proposed emission limit for these sources is 1,100 lb CO_2/MWh. EIA modeling projects that if the proposed rule were implemented, few, if any, new coal-fired units would be built and that those that are built would include CCS (79 FR 1430). If this rule becomes final, any new coal-fired power plants would likely require CCS in order to achieve the 1,100 lb CO_2/MWh emission limit.

In addition, given known technology and technological and demographic trends, EIA predicts that by 2040 natural gas will surpass coal as the largest share of U.S. electric power generation (EIA 2013a). This does not consider the proposed EPA rule described above, but indicates a general trend away from coal-fired facilities in favor of natural gas-fired power plants due to falling natural gas prices. MISO projects that the pending EPA regulations could lead to increased coal plant retirements, and estimates retirements between 3,000 MW to 12,600 MW, which could have a large impact on MISO’s reserve margin in the future (MISO 2011).

Although SCPC plants are currently the most widely used source of electricity generation within the ROI, given the potential for stringent air quality regulations and trends towards natural gas-fired power plants, the NRC staff does not consider SCPC to be a reasonable alternative to Byron license renewal. Instead, the NRC staff describes an IGCC plant under the coal alternative in Section 2.2.2.2.

2.4 Comparison of Alternatives

In this chapter, the NRC staff considered the following alternatives to Byron license renewal: new nuclear generation; IGCC generation; NGCC generation; a combination alternative of natural gas, wind, and solar; and purchased power. The no-action-by-NRC alternative and its effects also were considered. The impacts for all alternatives to Byron license renewal are discussed in Chapter 4 and summarized in Table 2–2 below.

The environmental impacts of the proposed action (issuing renewed Byron operating licenses) would be SMALL for all impact categories. The environmental impacts from all other alternatives would be larger than the proposed license renewal, as indicated in Table 2–2.

Table 2–2. Summary of Environmental Impacts of Proposed Action and Alternatives

Impact Area (Resource)	Byron License Renewal (Proposed Action)	No-Action	New Nuclear Alternative	IGCC Alternative	NGCC Alternative	Combination Alternative (NGCC, Wind, Solar)	Purchased Power
Land Use and Visual Resources							
Land Use	SMALL	SMALL	SMALL	SMALL TO MODERATE	SMALL	SMALL TO MODERATE	SMALL
Visual Resources	SMALL	SMALL	SMALL TO MODERATE	SMALL TO MODERATE	SMALL TO MODERATE	SMALL TO LARGE	SMALL
Air Quality and Noise							
Air Quality	SMALL	SMALL	SMALL	MODERATE	MODERATE	SMALL TO MODERATE	SMALL TO MODERATE
Noise	SMALL	SMALL	SMALL	SMALL TO MODERATE	SMALL	SMALL TO MODERATE	SMALL TO MODERATE
Geologic Environment	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Water Resources							
Surface Water Resources	SMALL	SMALL	SMALL TO MODERATE	SMALL TO MODERATE	SMALL	SMALL	SMALL TO MODERATE
Groundwater Resources	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Terrestrial Resources	SMALL	SMALL	SMALL TO MODERATE	MODERATE	SMALL TO MODERATE	SMALL TO MODERATE	SMALL
Aquatic Resources	SMALL	SMALL	SMALL	SMALL TO MODERATE	SMALL TO MODERATE	SMALL	SMALL
Special Status Species and Habitats	NO EFFECT	SEE NOTE[1]	SEE NOTE[1]	SEE NOTE[1]	SEE NOTE[1]	SEE NOTE[1]	SEE NOTE[1]
Historic and Cultural Resources	SEE NOTE [2]	NO EFFECT	SMALL	SMALL	SMALL TO MODERATE	SMALL TO LARGE	SMALL TO LARGE

Impact Area (Resource)	Byron License Renewal (Proposed Action)	No-Action	New Nuclear Alternative	IGCC Alternative	NGCC Alternative	Combination Alternative (NGCC, Wind, Solar)	Purchased Power
Socioeconomics							
Socioeconomics	SMALL	SMALL TO LARGE	SMALL TO MODERATE	SMALL TO MODERATE	SMALL TO MODERATE	SMALL	SMALL TO LARGE
Transportation	SMALL	SMALL	SMALL TO MODERATE	SMALL TO MODERATE	MODERATE TO LARGE	SMALL TO MODERATE	SMALL TO LARGE
Human Health	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Environmental Justice	SEE NOTE [3]	SEE NOTE [4]	SEE NOTE [5]	SEE NOTE [6]	SEE NOTE [7]	SEE NOTE [8]	SEE NOTE [9]
Waste Management and Pollution Prevention	SMALL	SMALL	SMALL	SMALL TO MODERATE	SMALL	SMALL	SMALL TO MODERATE

Notes:

[1] The magnitude of impacts could vary widely based on site selection and the presence or absence of special status species and habitats when the alternative is implemented; thus, the NRC staff cannot forecast a level of impact for this alternative.

[2] Based on (1) there being currently no NRHP-eligible historic properties in the APE, (2) tribal input, (3) Exelon's draft CRMP, (4) the fact that no license renewal-related physical changes or ground-disturbing activities would occur, (5) IHPA input, and (6) cultural resource assessment, license renewal would not affect any known historic properties (36 CFR Section 800.4(d)(1)).

[3] Continued operation of Byron would not have disproportionately high and adverse human health and environmental effects on these populations.

[4] The No-Action Alternative could disproportionately affect minority and low-income populations that may have become dependent on the public services in Ogle County.

[5] The new nuclear alternative would not have disproportionately high and adverse human health and environmental effects on minority and low-income populations.

[6] The IGCC Alternative would not have disproportionately high and adverse human health and environmental effects on minority and low-income populations.

[7] The NGGC Alternative would not have disproportionately high and adverse human health and environmental effects on minority and low-income populations.

[8] The Combination Alternative would not have disproportionately high and adverse human health and environmental effects on minority and low-income populations.

[9] The Purchased Power Alternative could be disproportionately affect low-income populations by increased utility bills because of the cost of purchased power. However, programs, such as the low income home energy assistance program in Illinois, are available to assist low-income families in paying for increased electrical costs.

In conclusion, the environmentally preferred alternative is the granting of a renewed license for Byron. All other alternatives capable of meeting the needs currently served by Byron entail potentially greater impacts than the proposed action of renewing the license for Byron. To make up the lost generation if a renewed license is not issued (the no-action alternative), one or a combination of alternatives would be implemented, all of which have greater impacts than the proposed action. Hence, the NRC staff concludes that the no-action alternative will have environmental impacts greater than or equal to the proposed license renewal action.

2.5 References

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3.0 AFFECTED ENVIRONMENT

In this supplemental environmental impact statement (SEIS), the "affected environment" is the environment that currently exists at and around Byron Station, Units 1 and 2 (Byron). Because existing conditions are at least partially the result of past construction and operation at the plant, the impacts of these past and ongoing actions and how they have shaped the environment are presented here. The facility and its operation are presented in Section 3.1. The affected environment is presented in Sections 3.2 to 3.13.

3.1 Description of Nuclear Power Plant Facility and Operation

Byron is a two unit nuclear power plant located in Ogle, Illinois. It began commercial operation in February 1985 (Unit 1) and January 1987 (Unit 2). Generally, the U.S. Nuclear Regulatory Commission (NRC) staff drew information about Byron's facilities and operation from Exelon Generation Company, LLC's (Exelon's) Environmental Report (ER) (Exelon 2013a).

3.1.1 External Appearance and Setting

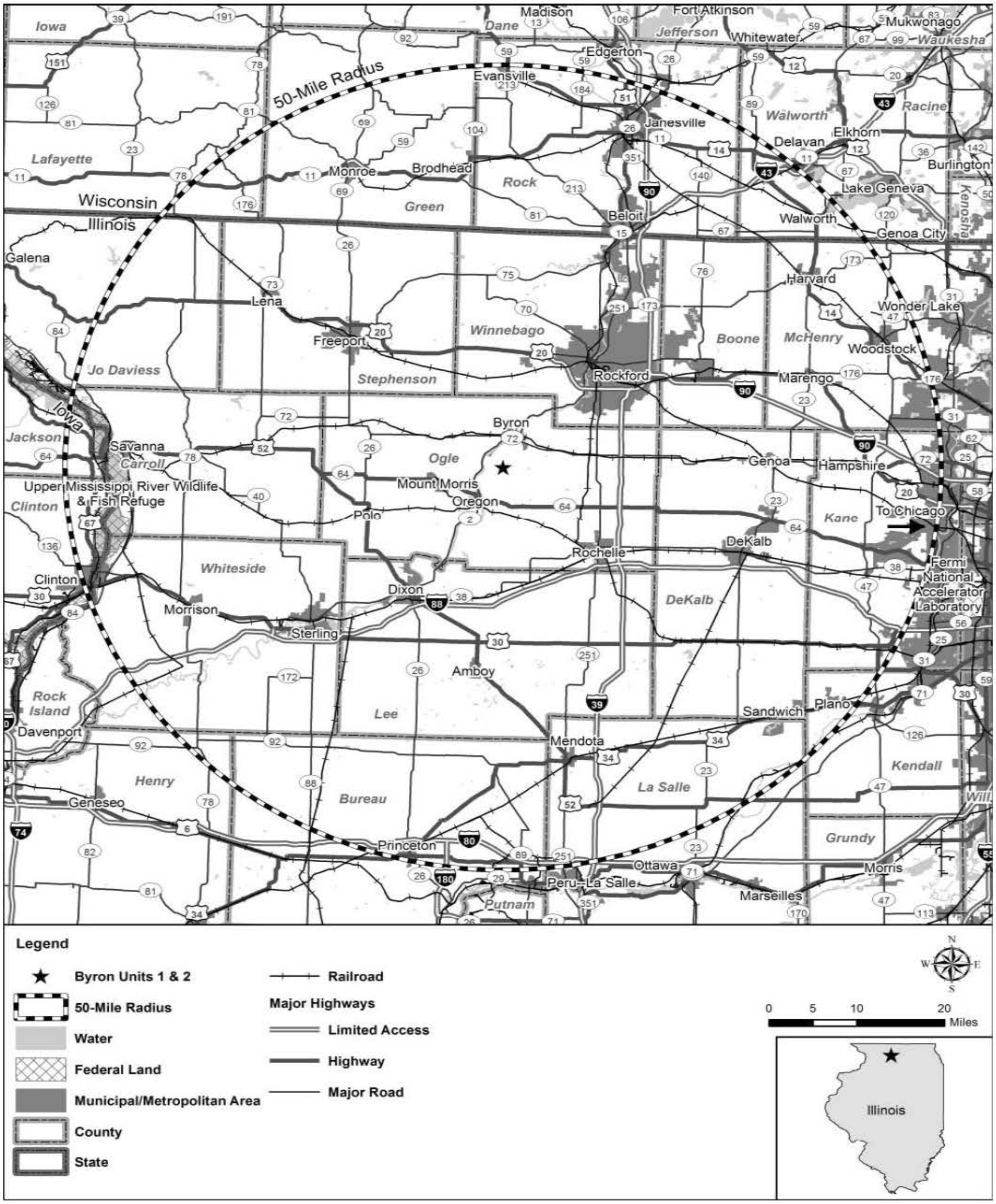
The Byron site is in northern Illinois near the center of Ogle County, approximately 90 mi (145 km) west-northwest of Chicago, 17 mi (27 km) southwest of Rockford, and 3.7 mi (6 km) south-southwest of the City of Byron (Figure 3–1) (Exelon 2013a).

The site is located on approximately 1,782 acres (ac) (721 hectares (ha)), and consists of the main site area and a right-of-way (ROW) to the Rock River for the circulating water makeup intake and blowdown discharge pipelines (Figures 3–2 and 3–3). The main site area occupies approximately 1,398 ac (566 ha), while the water pipelines' ROW occupies the remaining 384 ac (155 ha) (Exelon 2013a). The water intake and discharge pipelines' ROW runs from the northwest site boundary approximately 2 mi (3.2 km) west to the Rock River (Exelon 2013a).

The Byron site's main structures include two reactor containment structures and related facilities, two circulating water natural draft cooling towers, two essential service water mechanical draft cooling towers, a switchyard, and administration buildings, warehouses, and other features (Exelon 2013a).

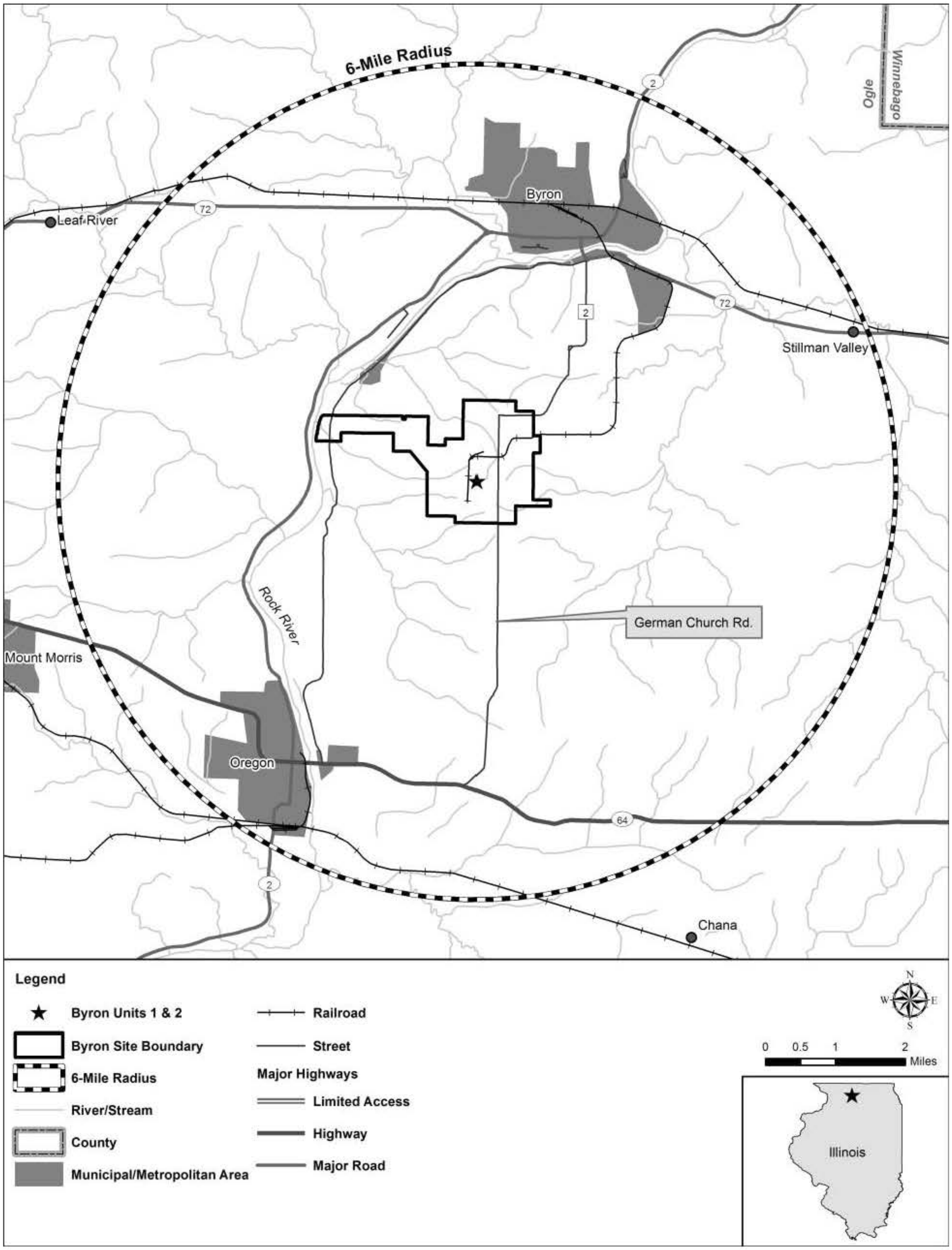
There are three ROWs that connect Byron to the regional electrical grid. These ROWs, which total approximately 1,210 ac (490 ha), are owned and maintained by Commonwealth Edison Company (ComEd) (Exelon 2013a).

Figure 3–1. Byron 50-Mile Radius Map



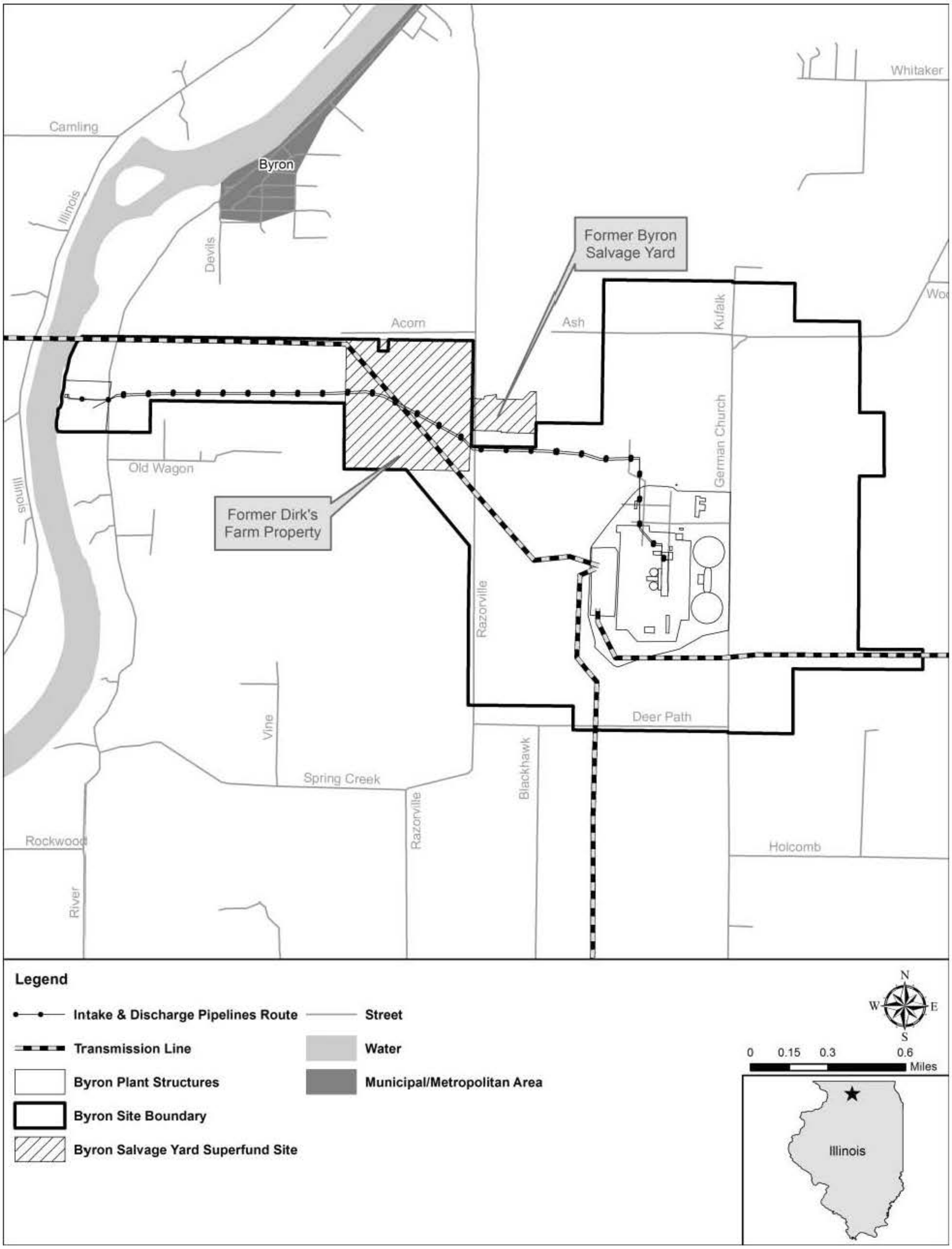
Source: Exelon 2013a

Figure 3–2. Byron 6-Mile Radius Map



Source: Exelon 2013a

Figure 3–3. Byron Site Boundary



Source: Exelon 2013a

The Byron Salvage Yard Superfund Site (Byron Salvage Site; not contaminated by activities at Byron) is by the north portion of the west side of the Byron site (Figure 3–3) and consists of two separate parcels: the Byron Salvage Yard and Dirk's Farm. The Byron Salvage Site is administered by U.S. Environmental Protection Agency (EPA) Region 5 and was proposed for listing on the Superfund National Priorities List (NPL) in 1982. The Dirk's Farm property is a former farm that is owned by Exelon and lies west of the Byron Salvage Yard. The Byron Salvage Yard property is a former automotive salvage yard and dump that is owned by ComEd. After the broader Byron Salvage Site was nominated for listing on the Superfund NPL, EPA performed a Remedial Investigation/Feasibility Study and initiated action under Superfund. In 2000, a Consent Decree was entered for remedial work on the Dirk's Farm property. The final remedial action for soils on the Dirk's Farm property was completed by Exelon in 2003, ending its responsibilities under the Consent Decree. A long-term groundwater monitoring plan for the Byron Salvage Yard Superfund Site was approved by EPA in 2003 (Exelon 2013a).

3.1.2 Nuclear Reactor Systems

The nuclear reactor for each of the two Byron units is a Westinghouse pressurized-water reactor (PWR) with four steam generators. Byron Units 1 and 2 entered commercial service on September 16, 1985, and August 21, 1987, respectively. On June 23, 2011, Exelon submitted a license amendment request to the NRC to increase the maximum power levels based on measurement uncertainty recapture (MUR) (Exelon 2011d). On February 7, 2014, the NRC staff issued license amendments approving the MUR and raised the rated thermal power to 3,645 megawatts thermal (NRC 2014a). At 100 percent reactor power, the combined net electrical output from both Byron units is approximately 2,370 megawatts electric (Exelon 2013a).

The Unit 1 steam generators are Babcock & Wilcox recirculating vertical U-tube units. The Unit 2 steam generators are Westinghouse recirculating vertical U-tube units. The original Byron Unit 1 steam generators were replaced in 1998; the Byron Unit 2 steam generators are original to the plant. The reactor coolant pumps are Westinghouse vertical, single-stage, centrifugal pumps equipped with controlled-leakage shaft seals (Exelon 2013a).

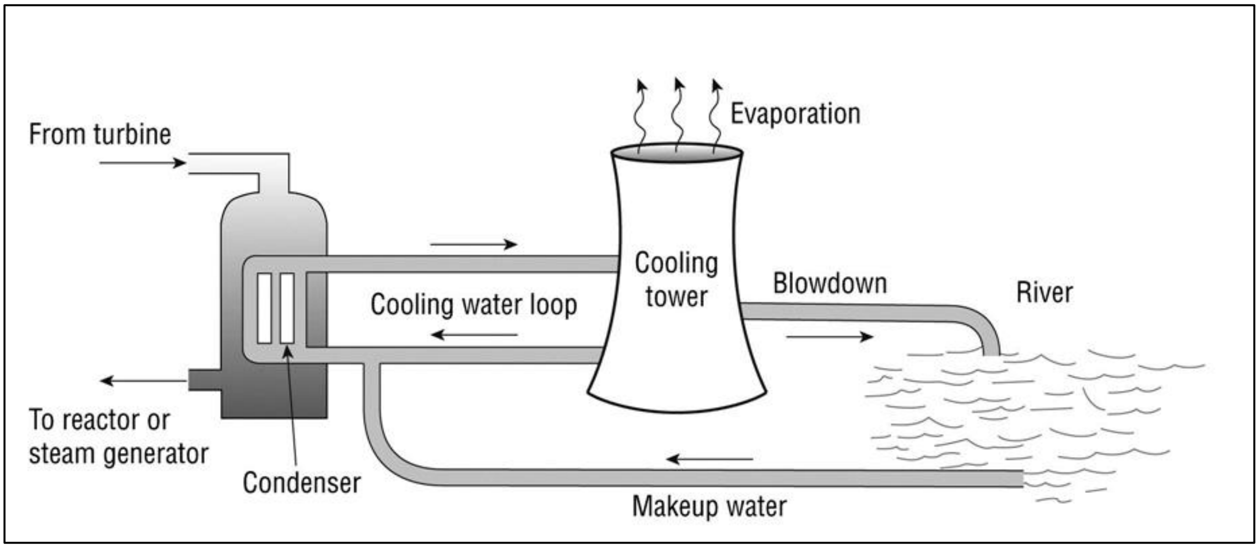
The reactor containment structure for each unit is a steel-lined, post-tensioned concrete vertical cylinder with a reinforced concrete base and a shallow dome (Exelon 2013a).

Both Byron units are licensed for low-enriched uranium dioxide fuel with enrichment to a nominal 5.0 percent by weight of uranium-235 and an allowable fuel burnup not to exceed 60,000 megawatt-days per metric ton (Mt) uranium. The uranium dioxide fuel is in the form of high-density ceramic pellets enclosed in Zircaloy-based tubing (Exelon 2013a).

3.1.3 Cooling and Auxiliary Water Systems

Byron uses a closed-cycle cooling tower-based heat dissipation system. In closed-cycle systems, water travels through the system to cool plant condensers and other system components and is then routed to cooling towers, which dissipate excess heat through evaporation. Water that is not lost to evaporation is either recirculated through the system as cooling water or discharged as blowdown (i.e., water that is periodically rinsed from the cooling system to remove impurities and sediment that may degrade plant performance) to a receiving water body. Water lost to evaporation or discharged as blowdown must be replaced; this replacement water is referred to as makeup water. Figure 3–4 provides a basic schematic diagram of a closed-cycle cooling system with a natural draft cooling tower. Byron has both natural draft cooling towers and mechanical draft cooling towers that service its three cooling and auxiliary water systems. All of Byron's systems withdraw makeup water from and discharge blowdown to the Rock River, which lies 2 mi (3.2 km) west of the Byron site's northwestern boundary. Unless otherwise cited, the description of Byron's cooling and auxiliary water systems is derived from Exelon's Environmental Report (ER) (Exelon 2013a) and Exelon's responses to the staff's requests for additional information (RAI) dated December 19, 2013 (Exelon 2013b).

Figure 3–4. Closed-Cycle Cooling System with Natural Draft Cooling Tower

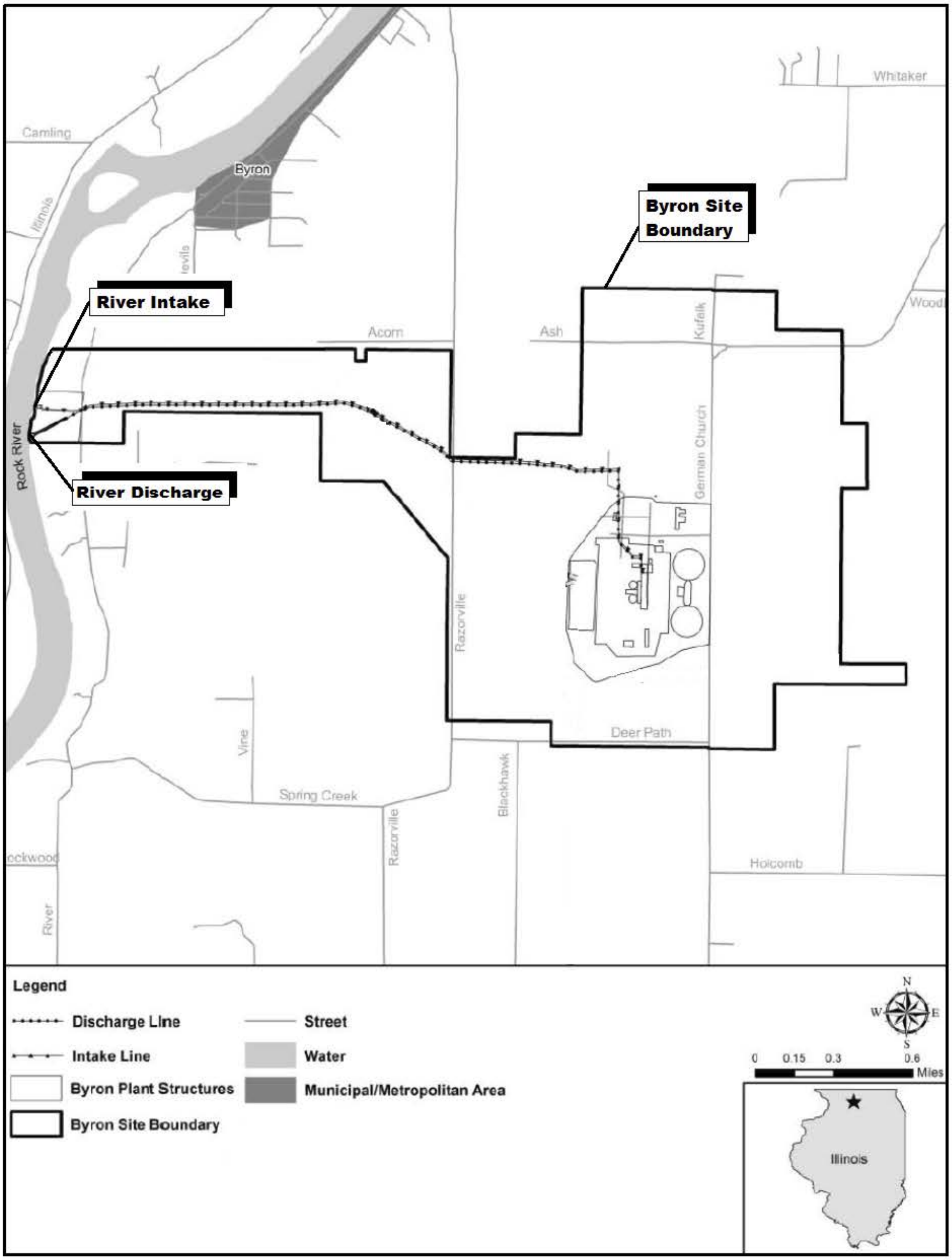


Source: NRC 2013a, modified from Figure 3.1-4

3.1.3.1 Circulating Water System

The circulating water system provides cooling water to the main condensers to cool the Byron reactor cores. At 100 percent power, each reactor unit requires 693,000 gallons per minute (gpm) (1,540 cubic feet per second (cfs) (43.5 cubic meters per second (m^3/s))—1,386,000 gpm (3,080 cfs (87 m^3/s)) in total—of circulating water to remove excess heat from the condensers. Following use for cooling, heated water is pumped to two natural draft cooling towers for heat dissipation where about 19,800 gpm (52.9 cfs (1.5 m^3/s) of water is lost to evaporation. The remaining water is routed to an open flume located between the two cooling towers. Water in the flume either enters the circulating water pump house, from which it is returned to the circulating water system, or it is discharged as blowdown. Byron discharges approximately 13,000 to 17,000 gpm (29 to 37.9 cfs (0.82 to 1.1 m^3/s) to the river as blowdown. Blowdown water travels from the flume through a 30-in. (76.2-cm) pipeline that runs west along Exelon's 2-mi (3.2-km)-long ROW to the Rock River (see Figure 3–5). The outfall structure lies about 61 m (200 ft) downstream of the intake point at the river screen house (described below). From the outfall structure, water discharges to the river through an 84-m (275-ft)-long rip-rapped channel.

Figure 3–5. Byron Cooling Water Intake and Discharge Pipelines



Source: Exelon 2013a, modified from Figure 2.1-3

To account for evaporative and blowdown losses, Byron's circulating water intake system withdraws an average of 36,750 gpm (81.8 cfs (2.3 m^3/s)) of makeup water. Typically, the Rock River near Byron flows at a rate of 6,033 cfs (170 m^3/s) (see Section 3.5.1.1). During low river flow (i.e., less than 679 cfs (19.2 m^3/s), Byron has an agreement with the Illinois Department of Natural Resources (IDNR) to limit Rock River water consumption to no more than 9 percent of total river flow during times when the river flow is at or below the specified low river flow. Commonwealth Edison Company made this agreement with the Illinois Department of Transportation (IDOT), Division of Water Resources (now IDNR) in 1977 during the process for obtaining a permit to construct the Byron intake and discharge structures (IDOT 1977). The permit also imposes a maximum withdrawal rate of 46,700 gpm (125 cfs (3.5 m^3/s)) regardless of the volume of flow in the river. Exelon has since incorporated the implementation of these permit conditions into several site procedures.

Makeup water is withdrawn from the Rock River through an intake structure on the east bank of the river (referred to as the "river screen house"), which is located at river mile (RM) 115 (river kilometer (RKm) 185) (see Figure 3–5). The river screen house has three dedicated makeup pumps, each with a capacity of 24,000 gpm (54 cfs or 1.5 m^3/s). Two of the pumps support normal operations and one serves as a backup. Prior to entering the intake structure, water flows at a speed of 0.43 to 0.55 feet per second (fps) (0.13 to 0.17 meters per second (m/s)) through trash racks located outside of the river screen house. The trash racks remove large debris and ice (in winter months) and are spaced 3 in. (8 cm) apart and extend from the intake channel floor to a height of 28 ft (8.5 m). Water then enters the screen house and is routed through traveling screens with 3/8-in. (0.95-cm) wire mesh openings. The design through-screen flow rate is 1.65 fps (0.5 m/s), but actual maximum through-screen velocity was measured as 0.91 fps (0.28 m/s) during preoperational impingement studies (IEPA 1989). The traveling screens operate automatically based on pressure differential, or if there is no pressure differential for a given period of time, every 12 hours for a period of 55 minutes. Debris and aquatic organisms collected on the screens are collected in trash baskets and disposed of off site. Following the traveling screens, circulating water makeup pumps direct water into a 48-in. (1.2-m) pipeline that runs approximately 2 mi (3.2 km) east from the river screen house to the boundary of the Byron site. The pipeline discharges into the flume between the cooling towers, at which point makeup water can enter the circulating water system through the circulating water pump house.

3.1.3.2 Nonessential Service Water System

The nonessential service water system provides water to non-safety-related systems. This system draws water from the circulating water pump house and returns water to the natural draft cooling towers. Makeup water from this system is supplied through the circulating water system's infrastructure, which is described above.

3.1.3.3 Essential Service Water System

The essential service water system removes heat from the reactor safeguard and auxiliary systems. During normal operations, this system draws water from the circulating water pump house, which pumps water to the auxiliary building, at which point water enters the essential service water system. The essential service water system also includes two 12-in. (0.3-m) intake pipelines that are dedicated to providing a source of backup makeup water during conditions in which makeup is not available from the circulating water system. The makeup pipelines run parallel to the circulating water system makeup pipelines from the river screen house to the site boundary and then to the mechanical draft cooling towers. These two mechanical draft cooling towers serve as the ultimate heat sink for the plant's two reactor units. Blowdown from these cooling towers is routed to the flume between the circulating water system's natural draft cooling towers.

3.1.3.4 Cooling and Auxiliary Water Treatment

Exelon treats each water system to prevent corrosion, scaling (i.e., the buildup of inorganic nutrients, such as calcium, magnesium, and silica), and biofouling. Exelon adds zinc to prevent corrosion; sulfuric acid, polyphosphate, potassium phosphate, acrylic polymer, and triazole to prevent scaling; sodium hypochlorite and sodium bromide to makeup water to prevent biofouling; and polyacrylate to disperse silt. Circulating water system makeup water is also treated with a low concentration of copper ions to prevent zebra mussel growth. Byron's National Pollutant Discharge Elimination System (NPDES) permit, which is discussed in more detail in Section 3.5.1.3, limits the chemical concentrations in blowdown discharged to the Rock River.

3.1.4 Radioactive Waste Management Systems

As part of normal operations and as a result of equipment repairs and replacements due to normal maintenance activities, nuclear power plants routinely generate both radioactive and nonradioactive wastes. Nonradioactive wastes include hazardous and nonhazardous wastes. There is also a class of waste, called mixed waste that is both radioactive and hazardous. The systems used to manage (i.e., treat, store, and dispose of) these wastes are described in this section. Waste minimization and pollution prevention measures commonly employed at nuclear power plants are also discussed in this section.

All nuclear plants were licensed with the expectation that they would release radioactive material to both the air and water during normal operation. However, NRC regulations require that gaseous and liquid radioactive releases from nuclear power plants must meet radiation dose-based limits specified in Title 10 of *Code of Federal Regulations* (10 CFR) Part 20, and the as low as is reasonably achievable (ALARA) criteria in Appendix I to 10 CFR Part 50. Regulatory limits are placed on the radiation dose that members of the public can receive from radioactive effluents released by a nuclear power plant. All nuclear power plants use radioactive waste management systems to control and monitor radioactive wastes.

Byron uses liquid, gaseous, and solid waste processing systems to collect and process, as needed, radioactive materials produced as a by-product of plant operations. The liquid and gaseous radioactive effluents are processed to reduce the levels of radioactive material prior to discharge into the environment. This is to ensure that the dose to members of the public from radioactive effluents is reduced to levels that are ALARA in accordance with NRC's regulations. The radioactive material removed from the effluents is converted into a solid form for eventual disposal at a licensed radioactive disposal facility.

Byron has a radiological environmental monitoring program (REMP) to assess the radiological impact, if any, to the public and the environment from radioactive effluents released during operations at Byron. The REMP measures the aquatic, terrestrial, and atmospheric environment for radioactivity, as well as the ambient radiation. In addition, the REMP measures background radiation (i.e., cosmic sources, global fallout, and naturally occurring radioactive material, including radon) (Teledyne 2013).

Byron has an Offsite Dose Calculation Manual (ODCM) that contains the methods and parameters used to calculate offsite doses resulting from liquid and gaseous radioactive effluents. These methods are used to ensure that radioactive material discharges from the plant meet NRC and EPA regulatory dose standards. The ODCM also contains the requirements for the REMP (Teledyne 2013).

3.1.4.1 Radioactive Liquid Waste Management

Radioactive liquids are processed as necessary by the liquid radwaste system (LRWS) for release to the environment into the Rock River via the circulating water blowdown line. The LRWS is designed so that liquid radwaste discharged from the site will have radioactive nuclide concentrations well within the limits specified in 10 CFR 20 and 10 CFR 50, Appendix I. The layout of the LRWS consists of two main subsystems designed for collecting and processing the liquid waste: the steam generator blowdown subsystem and the non-blowdown subsystem. Each of the liquid radwaste processing streams terminates in a monitor tank, allowing each batch of liquid waste to be sampled and analyzed to ensure they are ALARA before being released. Based on the analysis of each sample, these wastes are either released under controlled conditions via the cooling water system or recycled through the same or a different subsystem for further processing. The data from the analysis is used to ensure that the release conforms to the controls specified in the ODCM. The ODCM's controls are based on the concentration of radioactive material in the liquid effluent and the projected dose from the release.

Radioactive liquid waste is processed through a demineralizer system which removes soluble and suspended radioactive material using an ion exchange process and filtration prior to being released into the environment. Once the resin and filter media are expended, they are processed as waste for disposal.

The LRWS is shared by the two units; however, Unit 1 and Unit 2 have separate equipment and floor drain collection sump systems. The non-blowdown radwaste subsystem treats waste streams from the auxiliary building equipment drains, auxiliary building floor drains, chemical waste drains, regeneration waste drains, laundry drains, turbine building equipment and floor drains, and condensate polisher sump.

Radioactive liquid effluent paths are processed, monitored, and recycled or discharged via release tanks. Radioactivity analysis of the waste is performed prior to transferring the contents to the release tank. If the activity is below NRC regulatory release limits specified in the ODCM, the tank contents may be discharged to the Rock River via the circulating water blowdown line without further treatment. The blowdown line enters the Rock River approximately 61 m (200 ft) downstream of the water intake structure to prevent mixing of the wastewater with the makeup water lines. Prior to where the release tank discharge line mixes with the blowdown line, a backup radiation detector monitors the discharged liquid. If abnormal radiation levels are detected, a valve closes automatically to prevent the release and an alarm annunciates in the Control Room.

A spent resin storage tank stores the used demineralizer resins. The resin is held in this tank for a period of time to allow for the decay of short-lived isotopes. The resin is periodically removed for disposal as radioactive solid waste.

The use of these radioactive waste systems and the procedural requirements in the ODCM ensure that the dose from radioactive liquid effluents complies with NRC and EPA regulatory dose standards.

Dose estimates for members of the public are calculated based on radioactive liquid effluent release data and aquatic transport models. Exelon's annual radiological effluent release report contains a detailed presentation of the radioactive liquid effluents released from Byron and the resultant calculated doses. The NRC staff reviewed 5 years of radioactive effluent release data: 2008 through 2012 (Exelon 2009b, 2010c, 2011b, 2012c, 2013g). A 5-year period provides a data set that covers a broad range of activities that occur at a nuclear power plant such as refueling outages, routine operation, and maintenance activities that can affect the generation of radioactive effluents. The NRC staff compared the data against NRC dose limits and looked for indication of adverse trends (i.e., increasing dose levels) over the period of 2008 through 2012. The following summarizes the calculated doses from radioactive liquid effluents released during 2012:

Unit 1

- The total-body dose to an offsite member of the public from Byron Unit 1 radioactive liquid effluents was 8.03×10^{-2} millirem (mrem) (8.03×10^{-4} millisievert (mSv)), which is well below the 3 mrem (0.03 mSv) dose criterion in Appendix I to 10 CFR Part 50.
- The organ dose (adult/GI-tract) to an offsite member of the public from Byron Unit 1 radioactive liquid effluents was 1.38×10^{-1} mrem (1.38×10^{-3} mSv), which is well below the 10 mrem (0.1 mSv) dose criterion in Appendix I to 10 CFR Part 50.

Unit 2

- The total-body dose to an offsite member of the public from Byron Unit 2 radioactive liquid effluents was 8.03×10^{-2} mrem (8.03×10^{-4} mSv), which is well below the 3 mrem (0.03 mSv) dose criterion in Appendix I to 10 CFR Part 50.
- The organ dose (adult/GI-tract) to an offsite member of the public from Byron Unit 2 radioactive liquid effluents was 1.38×10^{-1} mrem (1.38×10^{-3} mSv), which is well below the 10 mrem (0.1 mSv) dose criterion in Appendix I to 10 CFR Part 50.

The NRC staff's review of Byron's radioactive liquid effluent control program showed that radiation doses to members of the public were controlled within NRC's and EPA's radiation protection standards contained in Appendix I to 10 CFR Part 50, 10 CFR Part 20, and 40 CFR Part 190. No adverse trends were observed in the dose levels.

Routine plant refueling and maintenance activities currently performed will continue during the license renewal term. Based on the past performance of the radioactive waste system to maintain doses from radioactive liquid effluents to be ALARA, similar performance is expected during the license renewal term.

3.1.4.2 Radioactive Gaseous Waste Management

The gaseous waste processing system (GWPS) is designed to remove fission product gases from the reactor coolant and minimize the amount of radioactive material released into the environment. The GWPS is a shared system serving both units. It consists of two waste-gas compression packages, six gas decay tanks, and the associated piping, valves, and instrumentation. Gaseous wastes are generated from the following activities: gases removed from the reactor coolant and purging of the volume control tank prior to a cold shutdown of the reactor, displacing of cover gases caused by the accumulation of liquids in storage tanks, purging of some equipment, sampling and gas analyzer operation, and operating the boron recycle system. The reduction of the levels of radioactive material is accomplished by internal recirculation of the gases within piping systems and temporary storage in gas decay tanks. The recirculation of the gases and the temporary storage in the decay tanks allows time for radioactive decay to reduce the levels of radioactivity.

Gaseous radioactive wastes are released into the atmosphere, in a controlled and monitored manner, through two mixed-mode release point ventilation stacks. The radioactive gaseous waste sampling and analysis program specifications provided in the ODCM address the gaseous release type, sampling frequency, minimum analysis frequency, type of activity analysis, and lower limit of detection (i.e., sensitivity) for the radiation monitor.

The use of these radioactive waste systems and the procedural requirements in the ODCM ensure that the dose from radioactive gaseous effluents complies with NRC and EPA regulatory dose standards.

Dose estimates for members of the public are calculated based on radioactive gaseous effluent release data and atmospheric transport models. Exelon's annual radioactive material release report contains a detailed presentation of the radioactive gaseous effluents released from Byron and the resultant calculated doses. The NRC staff reviewed 5 years of radioactive effluent release data: 2008 through 2012. A 5-year period provides a data set that covers a broad range of activities that occur at a nuclear power plant such as refueling outages, nonrefueling outage years, routine operation, and maintenance activities that can affect the generation of radioactive effluents. The NRC staff compared the data against NRC dose limits and looked for indication of adverse trends (i.e., increasing dose levels) over the period of 2008 through 2012. The following summarizes the calculated doses from radioactive gaseous effluents released during 2012:

<u>Unit 1</u>

- The air dose at the site boundary from gamma radiation in gaseous effluents from Byron Unit 1 was 4.36×10^{-4} millirad (mrad) (4.36×10^{-6} milligray (mGy), which is well below the 10 mrad (0.1 mGy) dose criterion in Appendix I to 10 CFR Part 50.
- The air dose at the site boundary from beta radiation in gaseous effluents from Byron Unit 1 was 3.07×10^{-3} mrad (3.07×10^{-5} mGy), which is well below the 20 mrad (0.2 mGy) dose criterion in Appendix I to 10 CFR Part 50.
- The dose to an organ (child bone) from radioactive iodine, radioactive particulates, and carbon-14 from Byron Unit 1 was 4.06×10^{-1} mrem (4.06×10^{-3} mSv), which is well below the 15 mrem (0.15 mSv) dose criterion in Appendix I to 10 CFR Part 50.

<u>Unit 2</u>

- The air dose at the site boundary from gamma radiation in gaseous effluents from Byron Unit 2 was 5.87×10^{-6} mrad (5.87×10^{-8} mGy), which is well below the 10 mrad (0.1 mGy) dose criterion in Appendix I to 10 CFR Part 50.
- The air dose at the site boundary from beta radiation in gaseous effluents from Byron Unit 2 was 1.19×10^{-5} mrad (1.19×10^{-7} mGy), which is well below the 20 mrad (0.2 mGy) dose criterion in Appendix I to 10 CFR Part 50.
- The dose to an organ (child bone) from radioactive iodine, radioactive particulates, and carbon-14 from Byron Unit 2 was 4.57×10^{-1} mrem (4.57×10^{-3} mSv), which is well below the 15 mrem (0.15 mSv) dose criterion in Appendix I to 10 CFR Part 50.

The NRC staff's review of Byron's radioactive gaseous effluent control program showed that radiation doses to members of the public were controlled within NRC's and EPA's radiation protection standards contained in Appendix I to 10 CFR Part 50, 10 CFR Part 20, and 40 CFR Part 190. No adverse trends were observed in the dose levels.

Routine plant refueling and maintenance activities currently performed will continue during the license renewal term. Based on the past performance of the radioactive waste system to maintain doses from radioactive gaseous effluents to be ALARA, similar performance is expected during the license renewal term.

3.1.4.3 Radioactive Solid Waste Management

Solid low-level radioactive waste (LLW) is generated by the removal of radioactive material from liquid waste streams, filtration of gaseous effluents, and removal of contaminated material from various reactor areas. The waste is divided into two categories: dry active waste (DAW) and wet active waste (WAW). The solid waste system collects, processes, packages, and provides temporary storage for WAW prior to offsite shipment and burial, in accordance with NRC regulations in 10 CFR Parts 61 and 71. Transportation of the radioactive solid waste is governed by the U.S. Department of Transportation (DOT) regulations in 49 CFR 171 to 178. The solid waste system also receives, decontaminates, compacts, and provides temporary storage for DAW prior to offsite shipment and burial.

Types of waste handled by this system include expended deep bed demineralizer resins, disposable cartridge filter elements, DAW (such as air filters, miscellaneous paper, rags from contaminated areas and contaminated clothing, tools, and equipment parts), and solid laboratory wastes. Drums are used for packaging both WAW and DAW. Byron has a drumming area where two remotely operated cranes are used to transport and position the drums while in storage, as well as transport them to trucks for offsite disposal.

Routine plant operation, refueling outages, and maintenance activities that generate radioactive solid waste will continue during the license renewal term. Radioactive solid waste is expected to be generated and shipped off site for disposal during the license renewal term.

3.1.4.4 Radioactive Waste Storage

Low-level radioactive waste is stored temporarily on site in restricted areas until it can be shipped off site for disposal at a licensed LLW disposal facility.

Byron stores its spent nuclear fuel in a spent fuel pool and also maintains an independent spent fuel storage installation (ISFSI) on site. The ISFSI is used to safely store spent fuel in licensed and approved dry cask storage containers on site. The installation and monitoring of this facility is governed by NRC requirements in 10 CFR Part 72, "Licensing requirements for the independent storage of spent nuclear fuel, high-level radioactive waste, and reactor-related Greater than class C waste." The Byron ISFSI would remain in place until the U.S. Department of Energy (DOE) takes possession of the spent fuel and removes it from the site for permanent disposal or processing. Expansion of the onsite spent fuel storage capacity may be required during the license renewal term. The impacts associated with this expansion would be assessed under the 10 CFR Part 72 license process separate from that of the Byron operating units. The Byron ISFSI is located within the existing protected area boundary. Spent fuel transfers to the ISFSI began in September 2010 when fuel from the spent fuel pool was placed in six casks and transferred to the ISFSI outdoor storage pad area and eight casks were added in 2012 (Teledyne 2013).

3.1.4.5 Radiological Environmental Monitoring Program

Exelon conducts a REMP to assess the radiological impact, if any, to the public and the environment from the operations at Byron.

The REMP measures the aquatic, terrestrial, and atmospheric environment for radioactivity, as well as the ambient radiation by sampling air, water, milk, foods, soil, fish, and shoreline sediment. In addition, the REMP measures background radiation (i.e., cosmic sources, global fallout, and naturally occurring radioactive material, including radon). The radiation detection devices and analysis methods used to determine the radioactivity in environmental samples are very sensitive to small amounts of radioactivity.

In addition to the REMP, Byron has an onsite ground water protection program designed to monitor the onsite plant environment for detection of leaks from plant systems and pipes containing radioactive liquid (Exelon 2013a). Information on the ground water protection program is contained in Section 3.5.2 of this document.

The NRC staff reviewed 5 years of annual radiological environmental monitoring data: 2008 through 2012 (Teledyne 2009, 2010, 2011, 2012, 2013). A 5-year period provides a data set that covers a broad range of activities that occur at a nuclear power plant such as refueling outages, routine operation, and maintenance activities that can affect the generation and release of radioactive effluents into the environment. The NRC staff looked for indication of adverse trends (i.e., buildup of radioactivity levels) over the period of 2008 through 2012.

The NRC staff's review of Exelon's data showed no indication of an adverse trend in radioactivity levels in the environment. The data showed that there was no measurable impact to the environment from operations at Byron.

3.1.5 Nonradioactive Waste Management Systems

Like any other industrial facility, nuclear power plants generate wastes that are not contaminated with either radionuclides or hazardous chemicals. These wastes include trash, paper, wood, and sewage.

Byron has a nonradioactive waste management program to handle its nonradioactive hazardous and nonhazardous wastes. The waste is collected in central collection areas within the plant site and managed in accordance with Exelon's procedures. The materials are received in various forms and packaged to meet regulatory requirements prior to final disposition at an offsite facility licensed to receive and manage the waste. Listed below is a summary of the types of waste materials generated and managed at Byron.

- Byron is registered as a small-quantity hazardous waste generator, however, hazardous wastes are managed according to large-quantity generator standards. The amount of hazardous wastes generated are only a small percentage of the total wastes generated; consisting of paints and paint-related materials, spent and off-specification and shelf-life expired chemicals, laboratory chemical wastes, and occasional project-specific wastes. Byron has contracts in place to transfer hazardous waste to licensed offsite treatment and disposal facilities.

- Byron's nonhazardous wastes include potentially infectious medical waste (PIMW), used oil, grease, antifreeze, adhesives, and other petroleum-based liquids. PIMW is generated at a health facility on site and can include used and unused hypodermic needles and syringes, as well as items contaminated with human blood. PIMW is considered a unique special waste category in Illinois and transportation and disposal of this waste is regulated under 35 Illinois Administrative Code (IAC) 1420.104 (a).

- Universal wastes, such as batteries and mercury-containing lamps.

- General plant trash is collected in dumpsters and transported to a state-licensed regional landfill permitted to accept solid wastes. General trash typically consists of garbage, paper, plastic, packing materials, leather, rubber, glass, soft drink and food cans, dead animals and fish, floor sweepings, ashes, wood, textiles, and scrap metal.

Exelon operates a sewage treatment package plant onsite. Effluent discharge is regulated under NPDES permit IL0048313. If the treatment plant is out of service, Exelon is authorized to transfer raw sewage up to 18,000 gallons per day (68,000 L/d) to the City of Oregon wastewater collection system for treatment. This effluent discharge is regulated under the town's NPDES permit IL0020184 (Exelon 2003).

3.1.6 Utility and Transportation Infrastructure

Existing utility and transportation infrastructure characteristics for Byron are briefly described in the following subsections.

3.1.6.1 Electricity

Byron receives offsite electrical power, as needed, from four different independent sources, via two separate power circuits from the 345-kV switchyard (Exelon 2013a). Each of these power circuits has its own separate ROW with independent transmission line structures. Byron also has two emergency diesel generators per unit designed to supply electrical power to key plant components when normal offsite power sources are not available (Exelon 2013d).

3.1.6.2 Fuel

Fuel is supplied to each diesel via the Fuel Oil System, which contains various tanks and fuel transfer pumps that provide fuel to each engine for a minimum of 7 days of operation without offsite support (Exelon 2013d). Byron's Fuel Oil System consists of four 25,000-gallon (gal) diesel oil storage tanks dedicated to Unit 1 and two 50,000-gal storage tanks dedicated to Unit 2 (Exelon 2013d).

3.1.6.3 Water

Systems designed to provide cooling water at Byron are described in Section 3.1.3. In addition to water needed for cooling, Byron requires water for sanitary purposes and for everyday use by personnel (e.g., drinking, showering, cleaning, laundry, toilets, and eyewashes). Byron draws potable water from the Cambrian-Ordovician Ironton-Galesville and Mt. Simon aquifers using two onsite groundwater wells, which also supply water to the demineralizer system (Exelon 2013a). As discussed in Section 3.1.5, Exelon operates an on-site sewage treatment package plant. Exelon is also authorized to transfer raw sewage to the City of Oregon wastewater collection system for treatment in the city's sanitary wastewater treatment plant.

3.1.6.4 Transportation Systems

Byron has extensive paved surfaces, including parking lots and roads connecting power plant infrastructure. Direct access to the site is via German Church Road (County Highway 2), which runs northeast-southwest (Exelon 2013a). Section 3.10.6 describes roadway access and other local transportation systems in more detail. The Canadian Pacific Railway provides a railroad spur to the Byron site (Exelon 2013a).

3.1.6.5 Power Transmission Systems

Transmission lines that are with the scope of the NRC's license renewal review are limited to those transmission lines that connect the nuclear plant to the substation where electricity is fed into the regional distribution system and transmission lines that supply power to the nuclear plant from the grid (NRC 2013a). Byron's main power transformers are connected via intermediate, onsite transmission lines to the onsite 345-kV switchyard (Exelon 2013a).

Commonwealth Edison Company is the owner and operator of the power transmission line systems for Byron, which connect the site to the Mid-America Interpool Network regional transmission grid (Exelon 2013a). No separate transmission lines supply offsite power to Byron from the grid (Exelon 2013a). Both switchyards and all the high-voltage lines would remain in service regardless of the proposed license renewal (ComEd 2013).

3.1.7 Nuclear Power Plant Operations and Maintenance

Maintenance activities conducted at Byron include inspection, testing, and surveillance to maintain the current licensing basis (CLB) of the facility and to ensure compliance with environmental and safety requirements. Various programs and activities currently exist at Byron to maintain, inspect, test, and monitor the performance of facility equipment. These maintenance activities include inspection requirements for reactor vessel materials, boiler and pressure vessel inservice inspection and testing, and maintenance of water chemistry.

Additional programs include those carried out to meet technical specification surveillance requirements, those implemented in response to the NRC generic communications, and various periodic maintenance, testing, and inspection procedures (Exelon 2013a). Byron must periodically discontinue the production of electricity for outages supporting refueling, periodic inservice inspection, and testing and maintenance activities. The Byron units are on staggered 18-month refueling cycles (Exelon 2013a).

3.2 Land Use and Visual Resources

3.2.1 Land Use

The Byron site is located in Ogle County in northern Illinois, approximately 3.7 mi (6.0 km) southwest of the City of Byron. Ogle County is the 17th largest county in Illinois and covers 763 square miles (mi^2) (1,976 square kilometers (km^2)). Ogle County is located within the Rock River Hill Country subsection in the Till Plains section of the Central Lowland physiographic province (IDNR 2001).

The most common land use within Ogle County is agriculture (89 percent), which includes farmsteads, farm buildings, pasture, grazing lands, timberlands, grasslands, and other rural open space uses. The major crops grown in Ogle County are corn and soybeans. Wheat, oats, and hay are also grown (Exelon 2013a). Livestock raised in Ogle County include cattle and hogs. Remaining land uses include municipalities (4.5 percent), rural settlements (1.5 percent), residential (1.0 percent), and state parks/forested land (1.0 percent) (Exelon 2013a; Ogle County 2012). Population growth in Ogle County has been minimal over the past decade (Exelon 2013a). The municipalities (the largest of which are Rochelle, Oregon, and Byron) account for only 4.5 percent of land use in Ogle County, although 57 percent of the county population resides within these areas (Exelon 2013a).

The Ogle County Illinois Comprehensive Plan 2012 Update (Ogle County 2012) is the County's land-use plan, and its goal is to:

> [establish] an identifiable destination that allows both the governing body and private interests to plan and budget with an idea as to the direction the County may move in the future, [and to] ensure that future growth is not only anticipated, but planned for.

In addition to this plan, Ogle County continues to implement its zoning and subdivision ordinances, greenways and trails plan, special flood hazards ordinance, comprehensive stormwater management ordinance, and municipality comprehensive land use plans (Exelon 2013a).

The Ogle County Greenways and Trails Plan (Sheaffer 2003) outlines the County's land use goals for green infrastructure. Green infrastructure and greenways are defined in this plan as recreational paths and trails, ecologically significant natural corridors, scenic and historic routes, networks of natural land forms (such as valleys and ridges), and urban waterfronts. The goals of the plan include development and conservation of greenways that contain multiple resources (particularly riparian areas), the protection of floodplains, the stabilization of native vegetation through the introduction of fragile soils, and the preservation of biodiversity and historic and cultural resources.

In Ogle County, one of the most important natural areas is the Lowden-Miller State Forest near the City of Oregon (IDNR undated). The forest is adjacent to Castle Rock State Park, which is named for a unique sandstone bluff on the Rock River. Combined, these two areas cover approximately 4,225 ac (1,710 ha). These areas contain important natural habitat and are home to more breeding pairs of forest bird species than any other part of Illinois (IDNR 2001). These parks and their terrestrial habitats are discussed further in Section 3.6.

Because Exelon's ER (Exelon 2013a) looked at land use within a 5-mi (8-km) radius of the Byron site, NRC staff used this radius during its review. Land use within this radius is primarily agricultural. Some residential land use is centered on the cities of Byron and Oregon, both of which are within 5 mi (8 km) of the Byron site, and the remaining areas are primarily rural. Within 5 mi (8 km) of Byron are eight privately owned recreational areas, one county park, and one state park. The Lowden Memorial State Park is 3.5 mi (5.6 km) to the southwest of the Bryon site and occupies 207 ac (84 ha). Weld Memorial Park, owned by Ogle County, is 3 mi (4.8 km) northeast and occupies 35 ac (14 ha). These parks offer such recreational activities to the public as camping, picnicking, hiking, fishing, and boating on the Rock River.

The Byron Salvage Yard Superfund Site lies beyond the northwest boundary of the main Byron site. The superfund site consists of two separate land parcels: the Byron Salvage Yard and Dirk's Farm (Exelon 2013a). Dirk's Farm was purchased by Exelon as part of Byron's circulating water pipeline ROW. The Byron Salvage Yard is not owned by Exelon. The automotive salvage yard portion of the Byron Salvage Yard was used as a dump for a variety of waste and debris. A contamination investigation and subsequent remediation began after several cattle deaths from cyanide-contaminated water occurred on Dirk's Farm in 1975 (EPA 2003). All soil and groundwater remedial actions are now completed on both sites and groundwater monitoring plans remain in place (EPA 2003).

The Byron site occupies 1,782 ac (721 ha), which consists of the main site area, which occupies 1,398 ac (566 ha), and the water intake and discharge pipeline corridor, which occupies 384 ac (155 ha) (Exelon 2013a). Figure 3–3 depicts the main site area, which is surrounded primarily by agricultural fields. The power block and support facilities (buildings, switchyard, parking lots, and roads) occupy approximately 154 ac (62 ha), or 9 percent of the main site area. The plant exclusion area is located entirely within the main site area boundary and all activities occurring within the exclusion area are controlled by Exelon. Exelon operates an ISFSI within the site boundary. The Byron site is bounded by County Highway 2 (German Church Road), Deer Path Road, and Razorville Road. County Highway 2 provides access to the Byron site from highways State Route 72 and State Route 64.

The pipeline corridor extends west of the main site area approximately 2 mi (3.2 km) to the Rock River. The Rock River creates the furthest western boundary of the Byron site. The pipeline corridor is surrounded on- and off-site by primarily wooded lands (Exelon 2013a). Byron's circulating water makeup intake structure is located at Rock River RM 115 (RKm 185), approximately 5 mi (8 km) downstream of the Byron, Illinois, U.S. Geological Survey (USGS) gaging station at Rock RM 120.3 (RKm 193.6). The Oregon Dam 4 mi (6.4 km) downstream creates the pool from which Byron draws its circulating water makeup and discharges its blowdown to and controls the water level at the intake.

Approximately 538 ac (218 ha) of the Byron site was disturbed during the construction of the Byron facilities (30 percent) (Exelon 2013b). Forty-seven percent of the Byron site (840 ac) (340 ha) has been leased for agricultural use. This land is considered disturbed because most of it is tilled. The remaining 23 percent (404 ac (163 ha)) of Byron is undisturbed land. Regarding control of leased land within the Byron site, Exelon Generation generally retains an unrestricted right to enter, use, and dispose of the leased land for its business purposes and in the event of emergencies. Also, subleases are not permitted and leases typically restrict use of the leased land solely to a designated purpose, such as for farming and agricultural purposes, for cultivating crops, or for pastureland. Some leases may prohibit certain specific activities on the leased land, such as removing top soil, changing the original ground grade level, altering the natural water drainage pattern, and installing irrigation systems.

3.2.2 Visual Resources

The Byron site is situated at one of the highest points within a 5-mi (8-km) radius, at 869 ft (265 m) mean sea level. The topography surrounding the Byron facility gently slopes downward in nearly all directions, including west to the bank of the Rock River. Predominant features at the Byron site include the two reactor containment buildings, a turbine building, an auxiliary building, a fuel handling building, service buildings, training buildings, a steam generator storage building, a circulating water pumphouse, a circulating water blowdown discharge structure, two natural draft cooling towers, two mechanical draft cooling towers, electrical switchyard, and an ISFSI (Exelon 2013a).

The tallest structures on site are the two natural draft cooling towers at approximately 495 ft (151 m) above the ground (NRC 2006). A visible plume of condensation rising from the cooling towers can be seen when the cooling towers are operating. The height and visibility of the plume depends on weather conditions, such as temperature, humidity, and wind speed. Most cooling tower plumes at Byron occur between the cooling tower top (495 ft (151 m)) and a height of 1,640 ft (500 m). Visible plumes may occasionally rise as high as 9,840 ft (3,000 m), although fewer than 10 percent of plumes are expected to ever exceed 3,280 ft (1,000 m). Visual impacts from natural draft cooling tower plumes at Byron are minimal in the summer and in cloudy weather. Impacts will be greatest on clear and calm winter days when plumes may reach higher elevations.

3.3 Meteorology, Air Quality, and Noise

3.3.1 Meteorology and Climatology

The Byron site is located near the center of Ogle County in northern Illinois, about 86 ft (139 km) west-northwest of Chicago. The site is located within Rock River Hill Country of the Till Plains Section of the Central Lowland Province in an agricultural area of gently rolling topography (ISGS 2013). The regional climate is continental with cold winters, warm summers, and frequent short fluctuations in temperature, humidity, cloudiness, and wind direction (NCDC 2013a). Weather systems create the wide variety of weather conditions that occur almost daily as a result of varying air masses and passing storm systems. Frequently, the polar jet stream is located near or over Illinois, especially in nonsummer months, which is associated with the creation and movement of low-pressure storm systems characterized by clouds, winds, and precipitation (NCDC 2013a). To some extent, the site is influenced by Lake Michigan, which is located as close as 76 mi (122 km) east of the site (NCDC 2013b).

The NRC staff obtained climatological data collected at the Rockford Airport National Weather Service (NWS) station, which is located about 13 mi (21 km) northeast of the site. Additionally, Byron maintains a meteorological facility that consists of a 250-ft (91-m) tower that is instrumented at two levels for wind and ambient temperature measurements (Exelon 2013b). Data from these stations was used to characterize the region's climate and are presented below.

For the 5-year period of 2008 to 2012, the average wind speed at the Rockford Airport NWS station was about 8.9 mph (4.0 m/s), with the highest at 10.3 mph (4.6 m/s) in spring and the lowest at 7.2 mph (3.2 m/s) in summer. Albeit not prominent, the prevailing wind direction was from the south (about 9.4 percent of the time). In general, southerly wind components are more frequent, followed by winds from northwesterly quadrant, from west through north. By season, wind blew from the south throughout the year, except from the west-northwest in winter. Wind speeds categorized as calm (less than 1.1 mph (0.5 m/s)) occurred about 14 percent of the time. The predominant wind direction at Byron for the 2008 to 2012 period was from the south with average annual wind speeds of 3.6 to 7.5 mph (1.6 to 3.4 m/s) (Exelon 2013b).

For the 62-year period, the annual average temperature at the Rockford Airport NWS station was 9.1 °C (48.3 °F) (NCDC 2013b). January was the coldest month with a mean monthly average of −6.8 °C (19.8 °F), while July was the warmest with a mean monthly average of 23.0 °C (73.4 °F). During the same period, the highest temperature of 40.6 °C (105 °F) was reached in July 2012, and the lowest of −32.8 °C (−27 °F) in January 1982. In warmer months, daytime maximum temperatures exceed 32.2 °C (90 °F) about 15 days per year, with a peak of 5.7 days in July. A daily minimum temperature at or below freezing is common during colder months (about 133 days per year), and subzero temperatures are recorded on about 11.5 days per year. The number of days with these temperatures peaked in January, about 29 days and 5.5 days, respectively. Temperature trends from recent observations (2008 to 2012) at the Byron site (Exelon 2013b) are consistent with temperature observations at the Rockford Airport NWS station.

For the 30-year period, annual precipitation at the Rockford Airport NWS station averaged about 36.2 in. (92.1 cm) (NCDC 2013b). On average, about 119 days per year have measurable precipitation (0.01 in. (0.025 cm) or higher). Summer is the wettest season, while winter is the driest season. Snow occurs as early as October and as late as April. On average, snowfalls are the highest in December, but peaks can occur in any of the three winter months. For the same period, the annual average snowfall was about 36.7 in. (93.2 cm), with the highest monthly snowfall of 30.2 in. (76.7 cm) in February 1994. Precipitation trends from recent observations (2008 to 2012) made at the Byron site (Exelon 2013b) are consistent with precipitation observations at the Rockford Airport NWS station.

Ogle County, where Byron is located, experiences severe weather events, such as floods, thunderstorm winds, and tornadoes. Other significant weather can be associated with these events; for example, lightning, hail, and high winds frequently occur with thunderstorms, and tornadoes can occur with thunderstorms. Since 1996, 10 floods, 49 hail events, and 5 tornadoes have been reported in Ogle County (NCDC 2013d). The tornadoes occurring in Ogle County were relatively weak, mostly either F0 or EF1 on the Fujita scale.[1]

[1] The original Fujita six-point scale (F0 to F5) was used to rate the intensity of a tornado based on the damage it inflicts to structures and vegetation from the lowest intensity, F0, to the highest, F5. In February 2007, the enhanced Fujita scale replaced the original Fujita scale. The enhanced Fujita scale still uses six categories of tornado intensity (EF0 to EF5), but the new scale more accurately matches wind speeds to the severity of damage caused by the tornado.

3.3.2 Air Quality

Under the Clean Air Act (CAA), the EPA has set primary and secondary National Ambient Air Quality Standards (NAAQS, 40 CFR 50) for six common criteria pollutants to protect sensitive populations and the environment. The NAAQS criteria pollutants include carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone (O_3), sulfur dioxide (SO_2), and particulate matter (PM). Particulate matter is further categorized by size—PM_{10} (aerodynamic diameter of 10 micrometers or less) and $PM_{2.5}$ (aerodynamic diameter of 2.5 micrometers or less).

The EPA designates areas of “attainment” and “nonattainment” with respect to the NAAQS. Areas that have insufficient data to determine designation status are denoted as “unclassifiable.” Areas that were once in nonattainment, but are now in attainment, are called “maintenance” areas; these areas are under a 10-year monitoring plan to maintain the attainment designation status. States have primary responsibility for ensuring attainment and maintenance of the NAAQS. Under section 110 of the CAA (42 U.S.C. 7410) and related provisions, states are to submit, for EPA approval, State Implementation Plans (SIPs) that provide for the timely attainment and maintenance of the NAAQS.

Air quality designations are generally made at the county level. For the purpose of planning and maintaining ambient air quality with respect to the NAAQS, EPA has developed Air Quality Control Regions (AQCRs). Air Quality Control Regions are intrastate or interstate areas that share a common airshed (40 CFR 81). The Byron site is located in Ogle County, Illinois; this county, along with the other four neighboring counties in Illinois and one county in Wisconsin, compose the Rockford (Illinois)-Janesville-Beloit (Wisconsin) Interstate AQCR (40 CFR 81.71). With regard to the NAAQS criteria pollutants, Ogle County is designated as an attainment/unclassifiable area for all criteria pollutants (40 CFR 81.314). Nearby designated nonattainment areas are McHenry County and Kane County for 8-hour ozone and $PM_{2.5}$, which are about 30 mi (49 km) east-northeast of and 35 mi (56 km) east of the site, respectively. McHenry County and Kane County are also designated maintenance areas for the $PM_{2.5}$ standard (78 FR 60704).

Byron has a number of stationary emission sources permitted through its Federally Enforceable State Operating Permit (FESOP Permit No. 141820AAA); these include standby emergency diesel generators, auxiliary boilers, auxiliary feedwater pumps, essential service water makeup water pumps, a fire pump, and two natural draft and two mechanical draft cooling towers (IEPA 2002). A source is eligible for a FESOP (also known as “synthetic minor” air permit) if the potential to emit (PTE) from the source triggers CAA Permit Program requirements, but maximum actual emissions are below, or can be restricted to remain below, major source thresholds. As reported and submitted to the Illinois Environmental Protection Agency (IEPA), actual total emissions from all sources at Byron from 2008 to 2012 are presented in Table 3–1 (Exelon 2009a, 2010a, 2011a, 2012a, 2013c). Annual emissions vary from year to year, but the highest emissions were reported in 2012. Byron has been in compliance with the requirements set forth in the air permit and there are no reported violations since October 1, 2011 (EPA 2014a).

Table 3–1. Air Emission Estimates for Permitted Combustion Sources at Byron [(a)]

	NO_x (t)[(b)]	CO (t)[(b)]	SO_x (t)[(b)]	$PM_{2.5}$ (t)[(b)]	PM_{10} (t)[(b)]	VOC (t)[(b)]	CO_2e (t)[(b)]
2008	18.83	4.98	0.05	20.32	20.32	0.63	965
2009	24.51	6.50	0.04	20.83	20.83	0.72	1,257
2010	21.35	5.66	0.02	20.42	20.42	0.71	1,099
2011	21.30	5.65	0.02	21.13	21.13	0.67	1,101
2012	28.29	7.51	0.02	23.12	23.13	0.90	1,501

[(a)] NO_x = nitrogen oxides; CO = carbon monoxide; SO_x = sulfur oxides; $PM_{2.5}$ = particulate matter with an aerodynamic diameter of 2.5 micrometers or less; PM_{10} = particulate matter with an aerodynamic diameter of 10 micrometers or less; VOC = volatile organic compound; CO_2e = carbon dioxide equivalent.

[(b)] To convert t (short tons) to MT (metric tons), multiply by 0.9072.

Sources: Exelon 2009a, 2010a, 2011a, 2012a, 2013c

On October 30, 2009, EPA published a rule for the mandatory reporting of greenhouse gases (GHGs) from sources that in general emit 25,000 MT or more of carbon dioxide equivalent (CO_2e)[2] per year in the United States (74 FR 56260). Most small facilities across all sectors of the economy fall below the 25,000-MT threshold and are not required to report GHG emissions to EPA. On June 3, 2010, EPA promulgated the Prevention of Significant Deterioration (PSD) and Title V GHG Tailoring Rule (75 FR 31514). Beginning January 2, 2011[3], operating permits issued to major sources of GHG under the prevention of significant deterioration (PSD) or Title V Federal permit programs must contain provisions requiring the use of best available control technology (BACT) to limit the emissions of GHGs if those sources would be subject to PSD or Title V permitting requirements because of their non-GHG pollutant emission potentials and their estimated GHG emissions are at least 75,000 tons/yr of CO_2 equivalents (CO_2e). As discussed above, Byron is a synthetic minor source and as shown in Table 3–1, GHG emissions from combustion sources at Byron are below the GHG Mandatory Reporting and Tailoring Rules thresholds; therefore, the NRC staff anticipates that Byron would be exempted from GHG emission limits. Additional GHG emission discussions are presented in Section 4.14 of this SEIS.

EPA promulgated the Regional Haze Rule to improve and protect visibility in national parks and wilderness areas from haze, which is caused by numerous, diverse sources located across a broad region (40 CFR 51.308–309). Specifically, 40 CFR 81 Subpart D lists mandatory Class I Federal Areas where visibility is an important value. The Regional Haze Rule requires states to develop SIPs to reduce visibility impairment at Class I Federal Areas. The nearest[4] Class I

[2] Carbon dioxide equivalents (CO_2e) is a metric used to compare the emissions of GHG based on their global warming potential (GWP). GWP is a measure used to compare how much heat a GHG traps in the atmosphere. GWP is the total energy that a gas absorbs over a period of time, compared to carbon dioxide. Carbon dioxide equivalent is obtained by multiplying the amount of the GHG by the associated GWP. For example, the GWP of methane (CH_4) is estimated to be 21; therefore, 1 t of methane emission is equivalent to 21 t of carbon dioxide emissions.

[3] On June 23, 2014, the U.S. Supreme Court issued a decision that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit, but could continue to require PSD and Title V permits, otherwise required based on emissions of conventional pollutants. In July 2014, the EPA issued a memorandum in response to the Supreme Court's decision and acknowledged that, while the decision is pending judicial action, the EPA will no longer require PSD or Title V permits for GHG-emitting sources that are not sources subject to PSD or Title V permits based on emissions of conventional pollutants (nitrogen oxides, carbon monoxide, etc.) (EPA 2014c).

[4] Rainbow Lake in Wisconsin is a Mandatory Federal Class I area where visibility is not an important air quality-related value. In 1980 Rainbow Lake was excluded for purposes of visibility protection as a Class I area. Rainbow Lake is approximately 505 km (314 mi) north-northwest of Byron.

Federal area for visibility protection is the Seney Wilderness Area in Michigan (40 CFR 81.414), about 323 mi (520 km) north-northeast of the Byron site. The next nearest Class I area is the Mingo Wilderness Area in Missouri (40 CFR 81.416), which is located about 350 mi 563 km) south of the site. Considering the distances to the nearest Class I areas and the minor nature of air emissions from the site, there is little likelihood that activities at the Byron site could adversely affect air quality and air quality-related values (e.g., visibility or acid deposition) in any of the Class I areas.

3.3.3 Noise

Any pressure variation that the human ear can detect is considered as sound, and noise is defined as unwanted sound. Sound is described in terms of amplitude (perceived as loudness) and frequency (perceived as pitch). Sound pressure levels are typically measured by using the logarithmic decibel scale. A-weighting (denoted by dBA) (ASA 1983, 1985) is widely used to account for human sensitivity to frequencies of sound (i.e., less sensitive to lower and higher frequencies and most sensitive to sounds between 1 and 5 kilohertz), which correlates well with a human's subjective reaction to sound. Several sound descriptors have been developed to account for variations of sound with time. The equivalent continuous sound level (L_{eq}) is a sound level that, if it were continuous during a specific time period, would contain the same total energy as a time-varying sound. Unless designated otherwise, all sound levels are instantaneous or L_{eq} values measured over short time periods. In addition, human responses to noise differ depending on the time of the day (e.g., higher sensitivity to noise during nighttime hours because of lower background noise levels). The day-night average sound level (L_{dn}) is a single dBA value calculated from hourly L_{eq} over a 24-hour period, with the addition of 10 dBA to sound levels from 10 p.m. to 7 a.m. to account for the greater sensitivity of most people to nighttime noise. Generally, a 3-dBA change over existing noise levels is considered to be a "just noticeable" difference, and a 10-dBA increase is subjectively perceived as a doubling in loudness and almost always causes an adverse community response (NWCC 2002). Table 3–2 presents common sound sources and their respective noise levels.

Table 3–2. Common Noise Sources and Noise Levels

Source	Noise Level (dBA)
Jet plane (at 100 ft distance)	130
Diesel truck (at 30 ft distance)	100
Food blender (at 3 ft distance)	90
Car (50 mph at 50 ft distance)	65
Conversation	55
Threshold of hearing	0

Sources: MMSHT 2008; SFU 1999

Nuclear power generation is an industrial process that can generate noise. Example noise sources at the Byron site include cooling towers, ventilation supply and exhaust fans, transformers, intake water pumps, transmission lines (corona discharge),relief valves, onsite vehicle traffic (commuter or delivery trucks), and shooting range activities (Exelon 2013c). Cooling towers and transformers are the primary contributing noise source as they are located outdoors and attributed to continuous plant operation.

In addition to natural background noise (e.g., birds chipping, wind), noise sources around Byron include agricultural activities, local traffic on rural roads, recreational activities (e.g., motorsports park), nearby community activities and events, and infrequent aircraft overflights. Nearby noise sensitive receptors include several residences (mostly farmhouses) scattered around the site but are more than 0.6 mi (9 km) from primary noise sources at Byron and a church (Ebenezer Reformed Church), which is located about 1.0 mi (1.6 km) south of primary noise sources at Byron (Exelon 2013b). Noise modeling studies were made at four receptor locations within and around the site property line (Exelon 2013b). Predicted noise levels ranged between 50 and 57 dBA L_{dn}, considering both the background and station contributions.

The activities at Byron would have to follow applicable Federal, State, or local guidelines and regulations on noise. Illinois has a noise regulation with allowable octave-band sound levels according to emitting and receiving land-use classification and time of day (IAC, Title 35: Environmental Protection, Subtitle H: Noise). The predicted noise levels from station operations are estimated to be below Illinois noise regulations (Exelon 2013b). Ogle County has noise ordinances with nuisance clauses against noise but has established no quantitative noise limits (Ogle County 2013). EPA uses a threshold level of 55 dBA L_{dn} to protect against excess noise during outdoor activities (EPA 1974). However, according to EPA this threshold does "not constitute a standard, specification, or regulation," but was intended to provide a basis for State and local governments establishing noise standards (EPA 1974). The Department of Housing and Urban Development (HUD) has established noise assessment guidelines and finds that a noise level of 65 dBA L_{dn} or less is acceptable (HUD 2013).

3.4 Geologic Environment

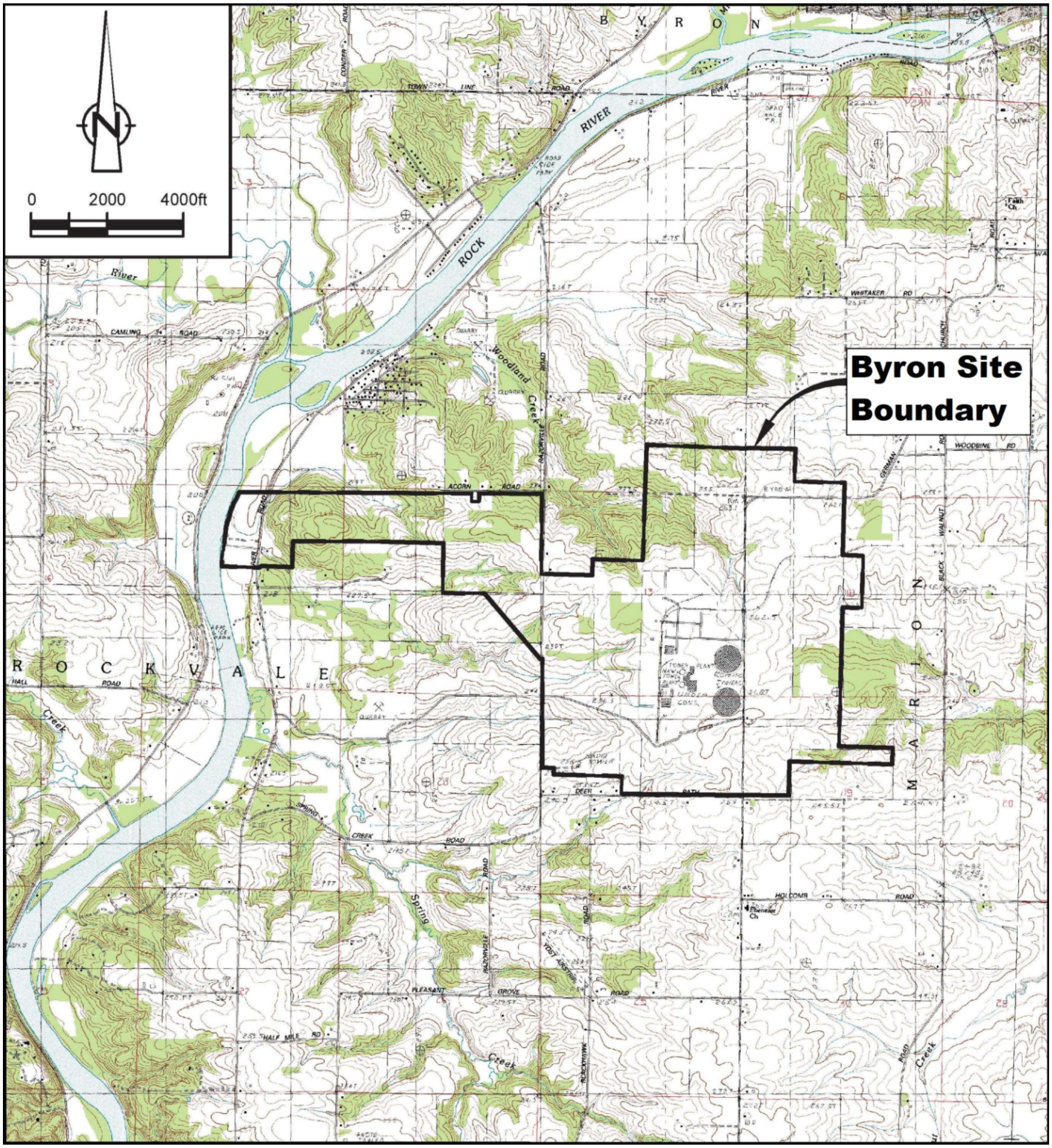
This section describes the geologic environment of the Byron site and vicinity, including landforms, geology, soils, and seismic conditions.

3.4.1 Physiography and Geology

The Byron site is located in the Rock River Hill Country Subsection of the Till Plains Section of the Central Lowlands Physiographic Province (Leighton et al. 1948). This subsection is characterized by gently rolling, dissected uplands covered by thin layers of glacial drift deposits (geologic material deposited by glaciers or glacier associated streams and lakes). The southwest-trending Rock River Valley runs through the eastern portion of the subsection.

The bedrock surface controls the topography (Figure 3–6), which consists of well-developed drainages surrounded by subdued rolling hills and some sharp ridges containing local exposures of bedrock (USACE 2006). Relatively thin glacial drift deposits of sand, silt, and glacial till (poorly sorted nonstratified sand, silt, and gravel) overlie the bedrock surface. The power station was constructed in an area where the bedrock is close to the land surface, and the foundation of the generating facility was built into the bedrock. Depth to bedrock increases near the Rock River, which is underlain by alluvium (stream deposits). The underlying bedrock consists of 2,000 to 3,000 ft (610 to 910 m) of dolomite, sandstone, and shale rock. In turn, these rocks are underlain by granites and granodiorites to a great depth (CRA 2006).

Figure 3–6. Site Topography



Source: CRA 2006

3.4.2 Soils

At Byron, most of the soils have formed in glacial drift. The soils developed in geologic material that was directly deposited by the glacier (moraine deposits), or deposited by melting glacial ice water (outwash deposits), or by wind (loess and dune deposits), or deposited by the Rock River and local streams. Almost all of these soils contain a large amount of fine-grained silt-sized material. Within the site boundary and along the pipeline that runs between the site and the river, most of the soils formed in moraine or outwash deposits. These soils are well-drained and are classified as silty loam or loam (USDA 2013).

3.4.3 Seismic Setting

The only reported injury from an earthquake that occurred in Illinois happened on April 12, 1883, when an old frame house was shaken down, resulting in slight injury to the inhabitants. A number of earthquakes (USGS 2013a, 2013b, 2013c) have originated within Illinois and include:

- May 26, 1909, a large earthquake knocked over many chimneys in Aurora and swayed buildings in Chicago.
- July 18, 1909, an earthquake knocked down chimneys in Petersburg.
- August 14, 1965, a sharp local earthquake knocked down chimneys at Elco, Unity, Olive Branch, and Olmstead.
- November 9, 1968, a magnitude 5.3 earthquake was felt over a large area.

Dozens of earthquakes originating outside Illinois have been felt inside the State without causing damage. These earthquakes originated in Missouri, Arkansas, Kansas, Nebraska, Tennessee, Indiana, Ohio, Michigan, Kentucky, and Canada. However, southern Illinois could experience major damage should a large-magnitude earthquake occur in the New Madrid Seismic Zone (located in southern Illinois and neighboring states) (MODNR 2013; USGS 2009). The site is located in northeast Illinois, which has a very small probability of experiencing damaging earthquakes (FEMA 2013; MAE Center 2009). The NRC requires every nuclear plant to be designed for site-specific ground motions that are appropriate for its location.

3.5 Water Resources

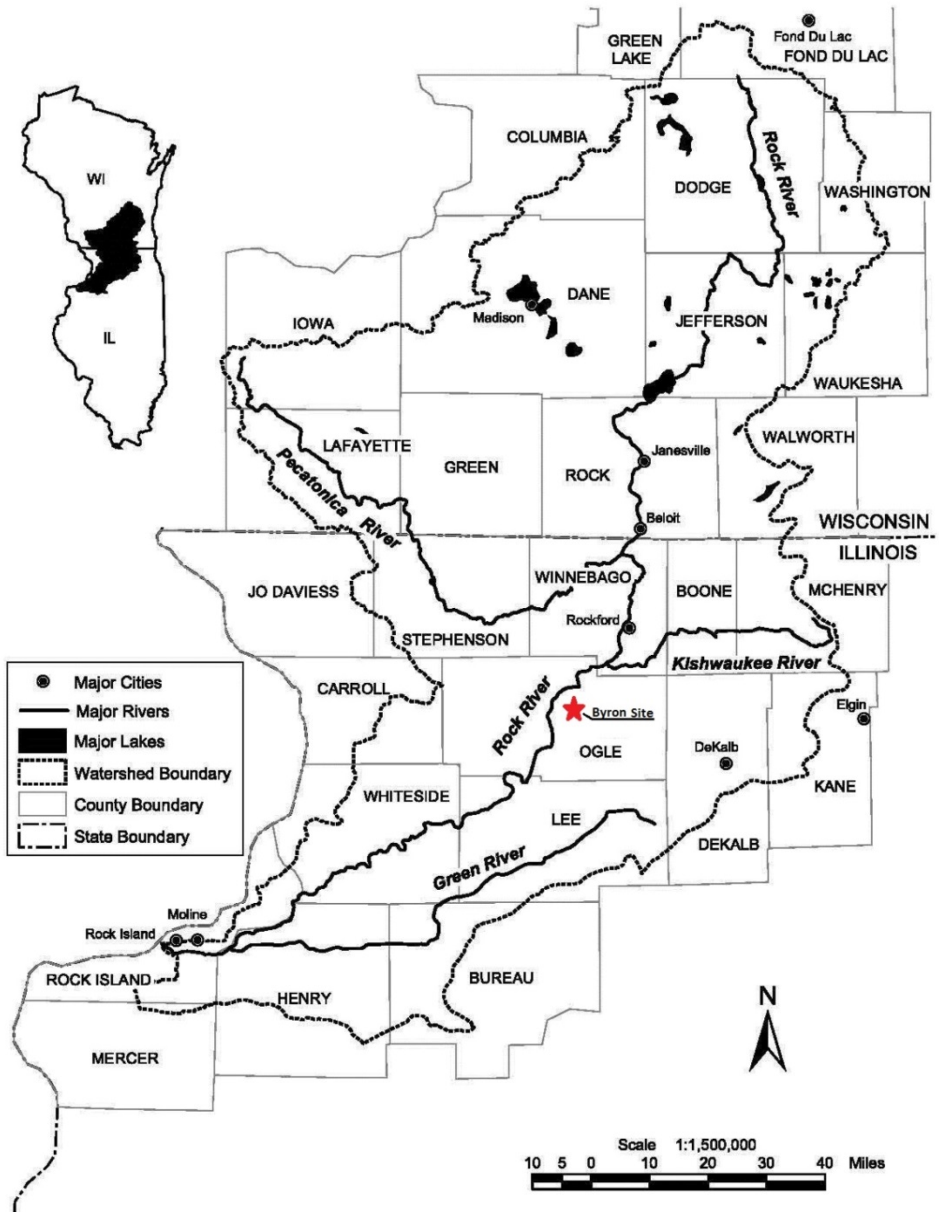
3.5.1 Surface Water Resources

This section describes surface water resources within and near Byron.

3.5.1.1 Surface Water Hydrology

The Rock River is the major surface water body in the region. It is located about 2 mi (3.2 km) to the west of Byron. The Rock River originates in southeastern Wisconsin and flows in a southwesterly direction into Illinois, ultimately discharging into the Mississippi River just downstream of Rock Island, Illinois (Figure 3–7). In total, the Rock River is approximately 318 mi (512 km) long, with about 163 mi (262 km) of that length in Illinois (IEPA 2006; Sinclair 1996). There are eight major dams on the river's main stem: Milan, Sterling, Rock Falls, Dixon, Oregon, Rockford, Rockton Spillway Lower, and Rockton Spillway Upper. These dams originally were built in the mid-1800s to early 1900s and are typically 10 to 15 ft (3 to 5 m) high (Knapp and Russell 2004). The dam at the City of Oregon, about 5 mi (8 km) downstream of Byron intake structure, forms the pool from which the station withdraws its makeup water and to which it discharges (Exelon 2013f; IEPA 2006).

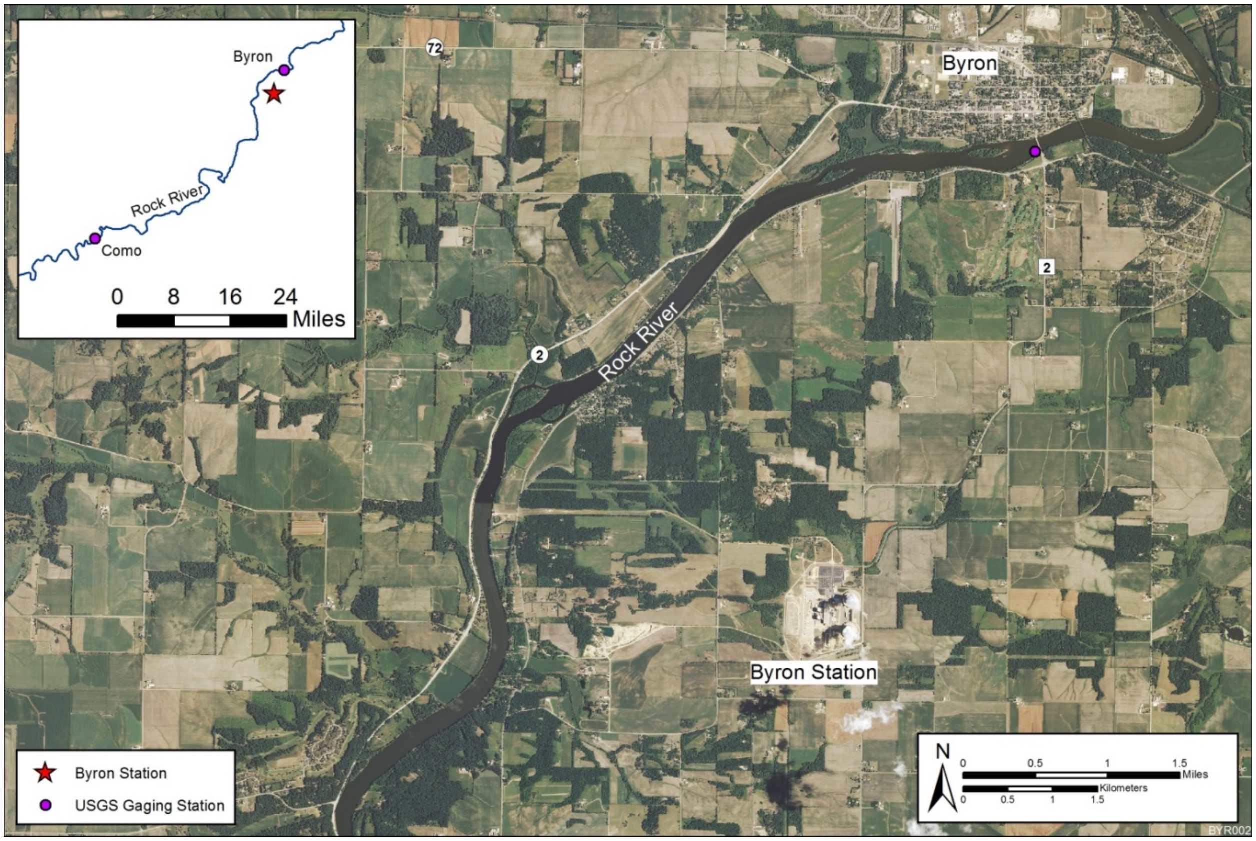
Figure 3–7. Rock River Basin in Illinois and Wisconsin



Source: modified from Knapp and Russell 2004

The river screen house (intake structure) at the Byron site is located on the Rock River's east bank at RM 115 (RKm 185) upstream from the river's confluence with the Mississippi River (Exelon 2013b). The USGS maintains a stream gaging station on the Rock River at the City of Byron, Illinois (station 05440700). This gage is located approximately 5 mi (8 km) upstream of the river screen house. Another stream gaging station is located at Como, Illinois (station 05443500). This gage is located approximately 46 mi (74 km) downstream of the river screen house (see Figure 3–8) (USGS 2013d). Discharge data from the City of Byron gage dates back only to May 2000 (12 years of record). Therefore, it may not be most representative of long-term river flow variability. The USGS gaging station at Como, Illinois, has a much longer reported record of river discharge (77 years). The mean annual river discharge measured at the USGS gage at Como, Illinois, for water years 1935 through 2012, is 6,033 cfs (170 m^3/s). The lowest average annual mean flow recorded over the period of record is 2,187 cfs (61.9 m^3/s). The mean 90 percent exceedance flow is 1,760 cfs (49.7 m^3/s) for the period of record. The 90 percent exceedance flow is an indicator value of hydrologic drought in a watershed (USGS 2013d, 20113e).

Figure 3–8. The Rock River and USGS Stream Gaging Stations in the Vicinity of Byron



Source: NRC Generated

At the plant site, the only notable surface water body is an engineered retention pond called the Construction Runoff Pond. This pond is part of the plant's storm drainage system and receives surface water runoff from the immediate vicinity of the plant. Prior to surface water reaching the pond, it passes through an oil-water separator. Discharges from this pond and all site storm water discharge is governed by the site's Storm Water Pollution Prevention Plan (Exelon 2013a). Storm water collected in the Construction Runoff Pond either flows to the Unit 2 natural draft cooling tower basin where it becomes part of the circulating water system or it flows through NPDES Outfall 003 via drainage ditches located along German Church Road to the north of the main plant complex. From there the water ultimately flows to Woodland Creek and from Woodland Creek to the Rock River (Exelon 2013a, 2013b). Byron's Storm Water Pollution Prevention Plan is implemented and maintained to comply with Special Condition 16 of the site's Illinois-issued NPDES permit. The site's NPDES permit is further discussed in Section 3.5.1.3.

3.5.1.2 Surface Water Use

As summarized in Section 3.1.3, Byron withdraws surface water from the Rock River to provide cooling water to the plant's steam turbine condensers and, secondarily, to the plant's nonessential service water (i.e., non-safety-related) system. Cooling tower blowdown and other permitted effluent streams are discharged back to the Rock River via the plant's primary NPDES outfall (Outfall 001) at a point located about 200 ft (61 m) downstream of the plant's intake at the river screen house.

Exelon reports that Byron's average makeup withdrawal rate has averaged about 36,750 gpm (81.9 cfs or 2.31 m^3/s), or about 52.9 million gallons per day (mgd) (200,000 m^3/day) (Exelon 2013a). NRC staff reviewed submittals by Exelon to the Illinois State Water Survey that recorded the volume of water intake and discharge from 2008 to 2012 (Table 3–3). Over that time period, Byron's surface water withdrawals averaged 83.2 cfs (2.35 m^3/s or 53.8 mgd) and the plant discharge rate to the Rock River averaged 30.3 cfs (0.86 m^3/s or 19.6 mgd). The remaining 52.9 cfs (1.5 m^3/s or 34.2 mgd) was consumed by the plant and lost to the atmosphere by evaporation and drift. In contrast, the maximum (nominal) surface water withdrawal rate for Byron Units 1 and 2 is 45,200 gpm (101 cfs or 2.85 m^3/s). This is equivalent to 65 mgd (246,000 m^3/day) (Exelon 2013a).

Table 3–3. Annual Surface Water Withdrawals and Return Discharges to the Rock River, Byron

Year	Withdrawals (mgy)	mgd	Discharges (mgy)	mgd
2008	19,142.4	52.4	7,083.0	19.4
2009	20,239.5	55.5	7,272.9	19.9
2010	20,265.0	55.5	7,462.9	20.4
2011	18,966.8	52.0	7,003.1	19.2
2012	19,530.0	53.5	6,855.1	18.8
Average	19,628.7	53.8	7,135.4	19.6

Note: Reported values are rounded. To convert million gallons per year (mgy) to million cubic meters (m^3), divide by 264.2.

Sources: Exelon 2008, 2009c, 2010d, 2011c, 2012e

Exelon limits the consumption of water from the Rock River by the Byron cooling systems (Exelon 2013b) to no more than 9 percent of total river flow when river flow is at or below 679 cfs (19.2 m^3/s) (Exelon 2013b). This limit was established by an April 1977 construction permit (No. 15001) from the IDOT, Division of Water Resources. The construction permit also contains a requirement that limits Byron's maximum makeup withdrawal rate from the river to 125 cfs (3.5 m^3/s) (Exelon 2013a, 2013b). This operational limit is prescribed by Byron's UFSAR (Exelon 2012d). A Byron plant operating procedure stipulates actions that plant personnel must take during low river flow. In summary, plant personnel monitor river flow using NWS and USGS data. When the river flow at the river screen house falls to 2,400 cfs (67.8 m^3/s) or less, daily monitoring of river flow is performed. If the calculated river flow falls to 679 cfs (19.2 m^3/s), personnel then begin to calculate and monitor consumptive water use. If consumptive use exceeds 9 percent of river flow, the procedure dictates that circulating water makeup and blowdown flows are to be reduced until the consumption of river water falls below

9 percent of the flow in the river. If further action is needed, the procedure requires the power output of the reactor units to be reduced to further lower consumptive water use (Exelon 2013b).

3.5.1.3 Surface Water Quality and Effluents

The Illinois Pollution Control Board, a sister Agency to the Illinois EPA, promulgates water quality standards in Illinois. Two Sections of Title 35 of the IAC (35 IAC 302; 35 IAC 303) contain standards applicable to lakes and streams. Procedures for the use of water quality standards in setting NPDES permit limits are found in Section 309 (35 IAC 309). Designated uses prescribed by 35 IAC 303 are those uses specified in water quality standards for each lake, river, stream, and groundwater resource. In designating uses for a water body, the Illinois Pollution Control Board takes into consideration a water body's value for public water supply; for propagation of fish, shellfish, and wildlife; and for recreational, agricultural, industrial, and navigational purposes (IEPA 2006).

The Rock River is designated as "general use water" by the Illinois Pollution Control Board. Water bodies designated as "general use water" must meet water quality standards protective of aquatic life, wildlife, agricultural use, secondary contact use, as well as most industrial uses and aesthetic quality (35 IAC 303). These standards pertain to pH, phosphorus, dissolved oxygen, radioactivity (gross beta, strontium-90, and radium-226 and -228), and various chemical constituents (metals and organic compounds), fecal coliform, and other toxic substances (as appropriate). Section 303(d) of the Federal Clean Water Act (CWA) requires the State of Illinois and other states to identify all "impaired" waters for which effluent limitations and pollution control activities are not sufficient to attain water quality standards (33 U.S.C. 1251 Section 303d). The 303(d) list identifies stream segments that require the development of total maximum daily loads to assure future compliance with water quality standards. The IEPA has identified a 25.1-mi (~42-km) long segment of the Rock River that includes the Byron site as impaired, because it does not meet water quality standards for three contaminants due to contamination from polychlorinated biphenyls (PCBs), mercury, and ethanol attributable to various upstream sources (IEPA 2012). .

The water quality of surface water discharges is regulated by the IEPA via the NPDES program. NPDES permits are issued by the IEPA on a 5-year cycle. Byron is currently operating under NPDES Permit No. IL0048313, issued on January 24, 2011; the permit expires on December 31, 2015 (Exelon 2013b; IEPA 2011). It specifies discharge standards and monitoring requirements for chemical releases, water temperatures, and for storm water discharges through the plant's outfalls to the Rock River and its tributaries. The outfalls are described in Table 3–4 and mapped in Figure 3–9.

The NPDES permit requires Exelon to monitor the flow rate, pH, suspended solids, and temperature of its cooling system blowdown discharge to the Rock River through its primary outfall (Outfall 001); other parameters include metals (zinc, iron, lead, copper, nickel, and chromium), hydrazine (an anticorrosive agent), oil and grease, 126 priority pollutants, and total residual chlorine/total residual oxidant (biocides agents). Sampling results are reported in monthly discharge monitoring reports submitted to the State. NRC staff reviewed discharge monitoring reports from 2008 through 2012 (Exelon 2013b) and found no "notice of violations" of NPDES permit requirements, unusual conditions of operations, or that effluent limitations were exceeded. As previously noted in Section 3.5.1.1, Exelon has prepared a storm water protection plan for Byron to manage its storm water discharges in compliance with Special Condition 16 of Byron's NPDES permit.

Table 3–4. National Pollutant Discharge Elimination System-Permitted Outfalls, Byron [a]

Outfalls	Average Flow Rate (mgd)	Description
001	20.3	Cooling tower blowdown; nonessential and essential service water blowdown and strainer backwash; discharges to the Rock River via rip-rapped channel
A01	0.019	Demineralizer regenerant waste; discharges via Outfall 001
B01	0.008	Sewage treatment plant effluent; discharges via Outfall 001
C01	0.028	Wastewater treatment plant effluent; discharges via Outfall 001
D01	0.022	Radwaste treatment plant effluent; discharges via Outfall 001
E01	0.119	Storm water runoff basin; discharges via Outfall 001
F01	Intermittent	Intake screen backwash; discharges to the Rock River via Outfall 001
002	Intermittent	Stormwater runoff basin overflow to Woodland Creek
003	Intermittent	East station area runoff to Woodland Creek
004	Intermittent	West station area runoff to unnamed tributary to Rock River

Note: To convert million gallons per day (mgd) to million cubic meters (m^3), divide by 264.2.

[a] Special Conditions 3 and 12 of the NPDES permit restrict temperature changes in the river and require Exelon to monitor the temperature of its discharge and provide the results in its monthly discharge monitoring report to the IEPA. When the river flow is less than 2,400 cfs (67.8 m^3/s) and/or the temperature differential between the main river temperature and the water quality standard is less than 3 °F (1.7 °C), compliance is to be demonstrated by calculations based on hourly measurements (averaged over a 24-hour period) of river flow, main river temperature, blowdown flow, and blowdown temperature values.

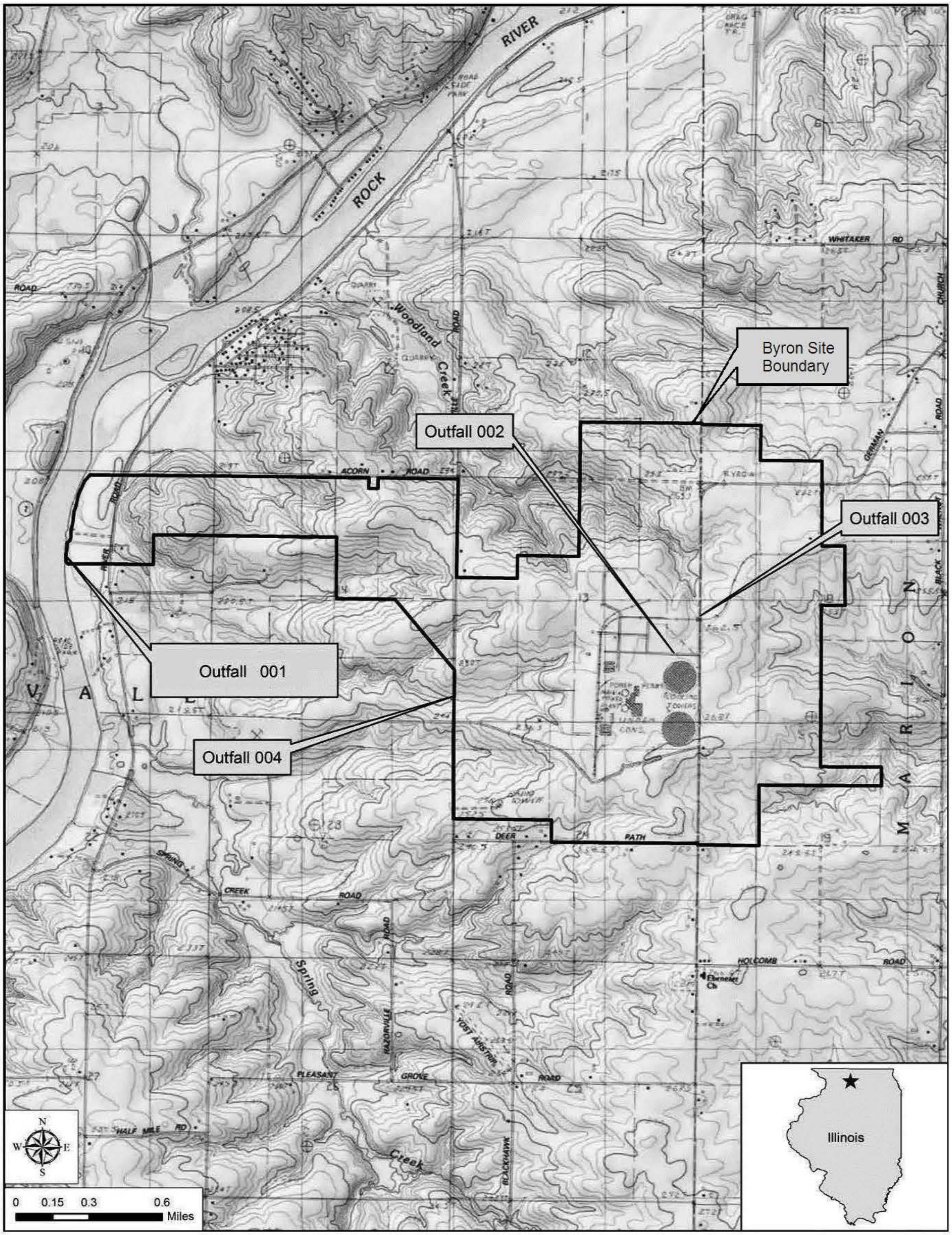
Outfalls A01, B01, C01, D01, E01, and F01 are internal monitoring stations for Outfall 001.

Source: IEPA 2011

An applicant (in this case Exelon) for a Federal license to conduct activities that may cause a discharge of regulated pollutants into navigable waters is required by Section 401 of the CWA to provide the licensing agency (in this case NRC) with water quality certification from the state (in this case the State of Illinois). This certification implies that discharges from the project or facility to be licensed will comply with CWA requirements and will not cause or contribute to a violation of state water quality standards. If the applicant has not received Section 401 certification, the NRC cannot issue a renewed license unless that state has waived the requirement. The NRC recognizes that some NPDES-delegated states explicitly integrate their 401 certification process with NPDES permit issuance. However, Byron's NPDES permit does not explicitly convey water quality certification under CWA Section 401.

The Rock Island District of the U.S. Army Corps of Engineers (USACE) sent a letter to Exelon in October 2012 stating that no permit was required from USACE and that it had no objection to renewing the Section 401 certification for Byron (Exelon 2013b). Previously, by letter dated July 2, 2012, Exelon submitted an application to the IEPA Bureau of Water Pollution Control requesting certification that renewal of the plant's NRC operating licenses would not violate state water quality standards (Exelon 2013b).

1 **Figure 3–9. NPDES Discharge Locations**



2

3 Source: modified from Exelon 2013b

In July 2013, the IEPA Division of Water Pollution Control responded to the Exelon request and sent a letter to the NRC regarding Byron's 401 certification providing the 401 certification subject to inclusion of two conditions into the NRC license for Byron (IEPA 2013). In November 2014, NRC staff responded to IEPA, noting that since the two conditions are license requirements either because they are imposed as a matter of law or they state existing statutory provisions, no further NRC action is needed with respect to these two conditions. Specifically, (1) Exelon must obtain CWA Section 402 (NPDES) permits from the State in accordance with 33 U.S.C. § 1342, and (2) a 401 certification does not authorize activities that require authorizations under Section 404 of the CWA, 33 U.S.C. § 1344 (i.e., the permits for discharges of dredged or fill material, which are issued by the USACE) (NRC 2014b).

To maintain the surface water intake system at the river screen house (see Section 3.1.3), Exelon conducts dredging to remove accumulated river sediment. The river bottom in the vicinity of the intake was engineered during plant construction to prevent the buildup of sediment and to maintain a connection to the cooler water in the main river channel. Specifically, a system of upstream wing dams and precast concrete turning vanes was constructed which directs cooling water toward the intakes while reducing scour and erosion of the opposite river bank (Exelon 2012d). While there is no prescribed frequency for dredging, divers are used to periodically examine intake area to assess the need to remove sediment. Dredging was performed at the river screen house in 2001 and again in 2007. Historically, both mechanical and hydraulic dredging has been conducted, with diver-assisted hydraulic dredging conducted most recently. Dredged river sediment is placed in a retention pond located in an upland area near the river screen house. Maintenance dredging at Byron is conducted via USACE Nationwide Permits in accordance with Section 10 of the Rivers and Harbors Appropriation Act of 1899 and Section 404 of the Clean Water Act (33 U.S.C. 403 Section 10 and 33 U.S.C. 1251 Section 404). Permit coverage for maintenance dredging activities at Byron was reaffirmed in a letter from the USACE to Exelon in September 2012 (Exelon 2013b).

3.5.2 Groundwater Resources

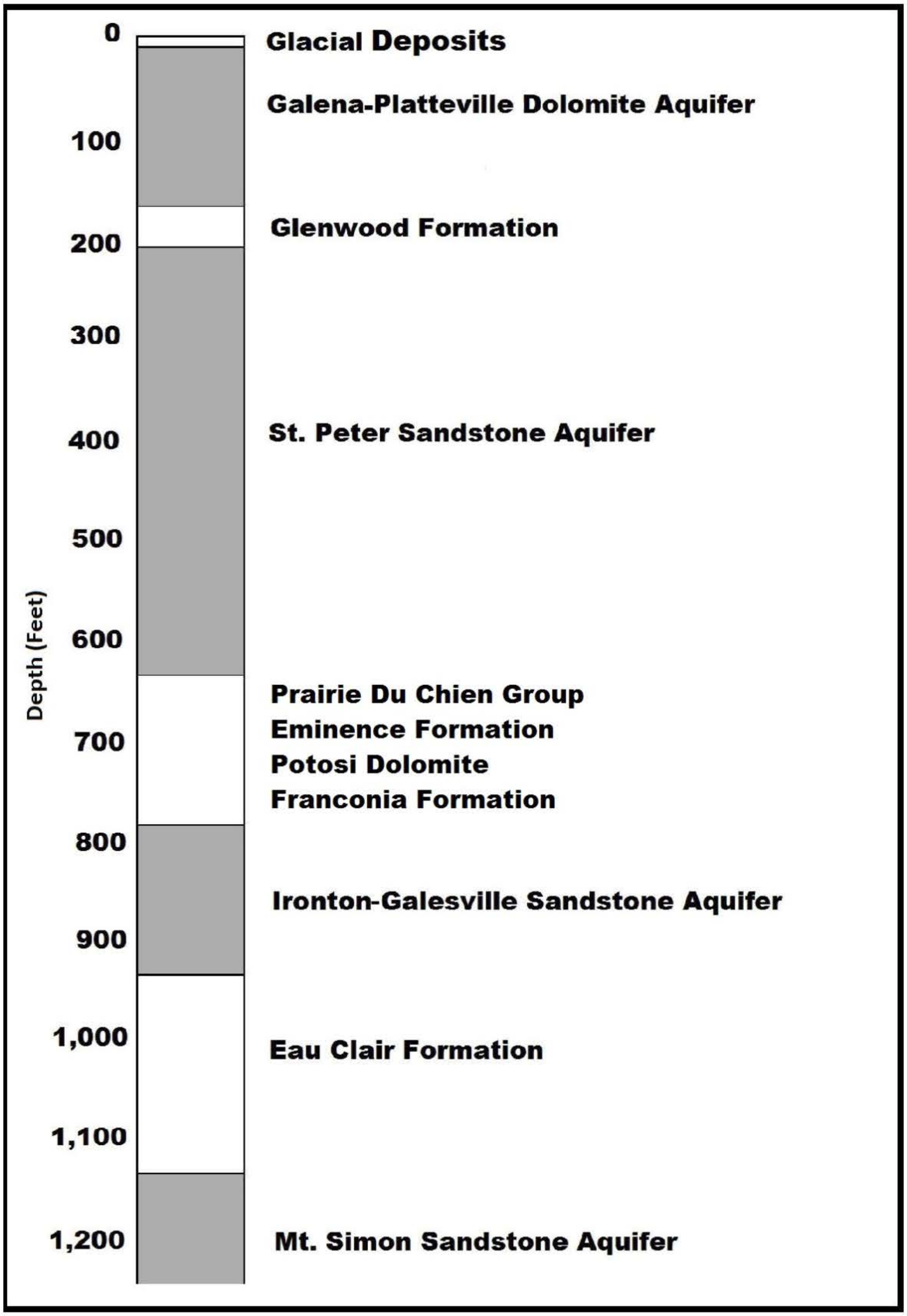
This section describes the current groundwater resources within and near the Byron.

3.5.2.1 Site Description and Hydrogeology

There are four significant hydrogeologic units in the area of Byron. These are (in order of increasing depth) (1) the glacial drift, (2) the Galena-Platteville Dolomite aquifer, (3) the sandstone units of the Cambrian-Ordovician Aquifer System (including the St. Peter Sandstone and Ironton-Galesville Sandstone aquifers), and (4) the Mt. Simon Sandstone aquifer (Figure 3–10). Glacial drift occurs as a thin mantle across the site, with the depth to the underlying bedrock varying from zero to 12 ft (3.7 m). Groundwater in the glacial drift is recharged by local precipitation. Because it is thin and has low permeability, the glacial drift has not been developed as a source of groundwater on a large scale (CRA 2006; Exelon 2013b).

The Galena-Platteville Dolomite aquifer underlies the glacial drift. It ranges in thickness from 100 to 225 ft (31 to 69 m). As with the glacial drift, recharge is by local precipitation. Groundwater in the glacial drift and in the Galena-Platteville Dolomite aquifer forms the local water table (CRA 2006; Kay et al. 1997). Groundwater movement in a water-table aquifer generally follows the local topography. Because Byron is situated on a topographic high, groundwater in the glacial drift and Galena-Platteville Dolomite aquifer flows from the site and discharges into the alluvium along the Rock River (Avery 1994). Groundwater in the Galena-Platteville Dolomite aquifer flows through the porous rock matrix and through fractures, joints, and solution openings. The aquifer provides modest yields for domestic use (Avery 1994; Exelon 2013b; IDNR 2002a; Kay et al. 1997).

Figure 3–10. Generalized Hydrogeologic Column of Byron



Source: NRC Staff Generated

The Galena-Platteville Dolomite aquifer is underlain by the Glenwood Formation, which is 37 ft (11.3 m) thick and is made up of sandstone, dolomite, and shale beds. The Harmony Hill Shale forms the top of this formation (Kay et al. 1997). This shale does not readily transmit groundwater (due to low permeability) and is about 5 ft (1.5 m) thick. Along with other shales, within the Glenwood Formation, it forms a semiconfining layer above the underlying St. Peter Sandstone aquifer (Kay et al. 1997) (Figure 3–11).

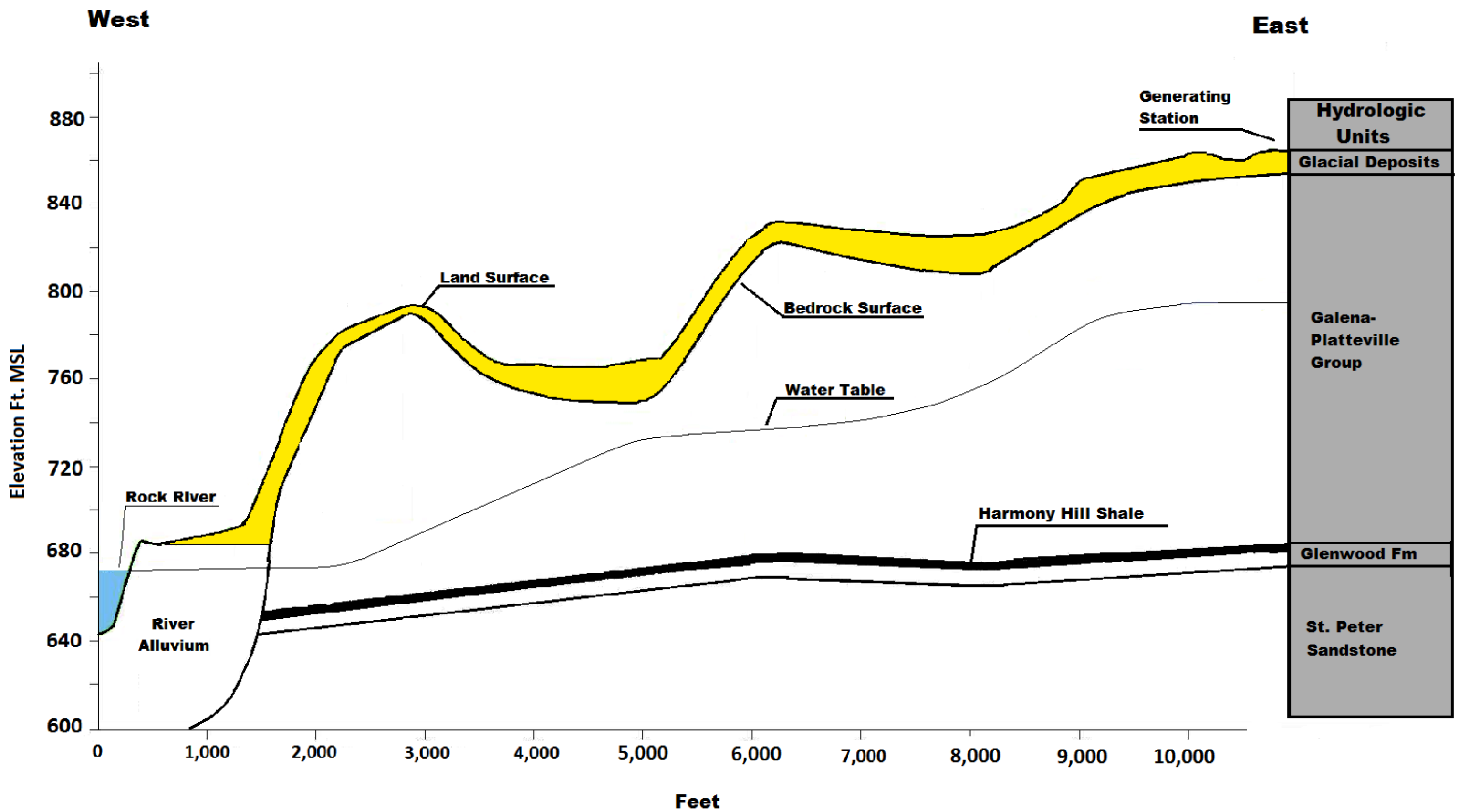
The St. Peter Sandstone aquifer underlies the Glenwood Formation. It is about 420 ft (128 m) thick and is a regional aquifer (Kay et al. 1997). It is fully saturated and, because of the shale beds within the overlying Glenwood Formation, it is semiconfined. However, near the Rock River, the St. Peter Sandstone aquifer is unconfined (under water table conditions), as the overlying geologic units have been eroded away at that location (Kay et al. 1997). The groundwater recharge areas of the St. Peter Sandstone lie outside the Byron site area in northern Illinois and southern Wisconsin. However, locally it does receive some additional groundwater recharge by vertical leakage through the Glenwood Formation (CRA 2006). From the site, groundwater in the St. Peter Sandstone aquifer flows westward and discharges to the alluvium along the Rock River (Avery 1994; Kay et al. 1997). As a regional aquifer, the St. Peter Sandstone aquifer supplies small municipalities and domestic and industrial activities that have water needs of less than 200 gpm (757 liters per minute (L/min)) (Avery 1994; Kay et al. 1997).

The St. Peter Sandstone aquifer is underlain by the Prairie du Chien Group, Eminence Formation, Potosi Dolomite, and Franconia Formation. These units are comprised mainly of dolomite and shale with some sandstone. These units are an estimated 150 ft (46 m) thick (Visocky et al. 1985) and act as a “confining unit” between the St. Peter Sandstone aquifer and the underlying Ironton-Galesville Sandstone aquifer (Burch 2008).

The Ironton-Galesville Sandstone aquifer can be a productive source of groundwater and has an estimated thickness of about 150 ft (46 m). Together the St. Peter Sandstone aquifer and the Ironton-Galesville Sandstone aquifer make up the regional aquifer known as the Cambrian-Ordovician Aquifer System. This system is a significant source of water across northern Illinois (Burch 2008). The Eau Claire Formation underlies the Ironton-Galesville Sandstone aquifer. It has an estimated thickness of 200 ft (61 m). Because of its shale content, it is not considered to be an aquifer and acts as an aquitard (confining unit) (Sasman and Baker 1966; Visocky et al. 1985).

The Eau Claire Formation is underlain by the Mt. Simon Sandstone aquifer, which is a fine- to course-grained sandstone with gravel. The Mt. Simon Sandstone aquifer has an estimated thickness of about 1,500 to 2,000 ft (457 to 610 m) thick. It is capable of yielding moderate amounts of water (Sasman and Baker 1966; Visocky et al. 1985). Deeper sections of the Mt. Simon Sandstone aquifer (1,300 ft below sea level) are commonly too salty for municipal use (Sasman and Baker 1966).

Figure 3–11. Generalized East–West Hydrogeologic Cross Section



Source: modified from CRA 2006

3.5.2.2 Groundwater Use

Most of the water for municipal, domestic, and industrial use in the region is obtained from the St. Peter Sandstone aquifer. The nearest public water supply is the Northern Illinois University Lorado Taft field campus well field, located about 3.5 mi (5.6 km) to the southwest of the Byron. Here groundwater is withdrawn from two wells completed in the St. Peter Sandstone aquifer. The City of Byron, located about 4 mi (6.4 km) northwest of the station, uses groundwater from wells completed in the Ironton-Galesville Sandstone and Mt. Simon Sandstone aquifers (Exelon 2013b).

Two wells, W-1 and W-2, provide Byron with all its potable and demineralizer water supplies. The onsite wells extend to a depth of 1,500 ft (457 m) and produce water from the Ironton-Galesville Sandstone and the Mt. Simon Sandstone aquifers. Each well has a maximum capacity of 800 gpm (3,028 L/min) and when both wells are in operation, they can supply Byron with water at 1,600 gpm (6,056 L/min). This high pumping capacity is available as an emergency backup water supply, in the event that essential cooling tower makeup water is not available from the Rock River. Exelon files annual reports documenting its groundwater withdrawals with the Illinois State Water Survey (Exelon 2013b). Groundwater consumption varies depending on the activities conducted at the plant. The peak demand for groundwater is usually associated with refueling and maintenance activities. This activity could require up to 470 gpm (1,779 L/min) (Exelon 2013b). However, this rate of groundwater consumption is of short duration. As a result, yearly groundwater use between 2008 and 2012 ranged from 18 gpm to 43 gpm (68 to 163 L/min) and averaged 30 gpm (114 L/min) (Exelon 2009c, 2010d, 2011c, 2012e; Teledyne 2008).

3.5.2.3 Groundwater Quality

All of the groundwater aquifers previously discussed can supply good quality water. However, northwest of the site, groundwater quality in the Galena-Platteville Dolomite aquifer has been contaminated and degraded by the Byron Salvage Yard Superfund Site. The Byron Salvage Yard Superfund Site occupies an area of about 180 ac (73 ha) near the northwest corner of the Byron site (IDPH 2005). The groundwater quality at the Byron Salvage Yard Superfund Site was not contaminated by any activities associated with Byron. During the 1960s and 1970s, the owner of the Byron Salvage Yard accepted electroplating wastes and other waste materials such as oil sludge, paint sludge, cutting wheels, solvents, and scrap metal. These materials were buried at the Byron Salvage Yard Superfund Site and in some areas dumped on the ground.

In 1976, the IEPA confirmed the presence of volatile organic compounds (VOCs) and heavy metals in the soil, surface water, and groundwater at the Byron Salvage Yard Superfund Site. Contaminants in groundwater include vinyl chloride, trichloroethylene, and cyanide (EPA 2013a). From the Byron Salvage Yard Superfund Site, two plumes of contamination are moving laterally within the Galena-Platteville aquifer. One plume moved northwest and one plume moved southwest (Kay et al. 1997). Both plumes are moving toward the Rock River. Cleanup and groundwater remediation activities at the Byron Salvage Yard Superfund Site have been ongoing since 1975. Groundwater monitoring will continue at the Byron Salvage Yard Superfund Site until contaminant levels fall below safe drinking water standards (EPA 2013a).

Beginning in 2006, Exelon conducted a groundwater investigation of the discharge (blowdown) pipeline that runs from the plant to the Rock River. As part of this investigation, multiple samples were obtained from the pipeline, from vacuum breaker vaults installed along the pipeline, from nearby residential wells, and from monitoring wells. Other than tritium, no radionuclides were or have since been discovered above their lower limit of laboratory detection. As reported in 2007, tritium was detected above the lower limit of detection in four monitoring wells (AR-2, AR-3, AR-4, and AR-11). These wells are located close to three vacuum breaker vaults: VB-2, VB-3, and VB-4. The tritium concentrations in these wells ranged from 327 picocuries per liter (pCi/L) to 3,050 pCi/L. These concentrations were well below the EPA drinking water standard for tritium of 20,000 pCi/L. No tritium was detected in residential wells or found to be moving off site at detectible concentrations (CRA 2006).

Exelon continued to investigate tritium releases from the discharge (blowdown) pipeline in cooperation with the IEPA, the Illinois Attorney General's Office, and the NRC. In March 2010, Exelon agreed to a consent order with the State of Illinois that was approved by the Circuit Court for the Fifteenth Judicial Circuit (Ogle County). The consent order required Exelon to prevent further releases of regulated wastewater to soil, surface water, or groundwater at Byron and to operate continuous monitoring systems in the vacuum breaker vaults along the pipeline. Exelon has complied with the consent order. The consent order was terminated in March 2011 (Exelon 2013b), but Exelon continues to monitor the groundwater and vacuum breaker vaults.

By 2012, tritium was detected in only two wells adjacent to the pipeline (AR-4 and AR-11). Tritium levels in well AR-4 had declined from 3,050 pCi/L in 2007 to 830 pCi/L in 2012, and tritium levels in well AR-11 had declined from 1,820 pCi/L in 2007 to 994 pCi/L in 2012 (Exelon 2013b; Teledyne 2008). Tritium concentrations in these two wells continue to be well below the EPA drinking water standard of 20,000 pCi/L.

Exelon routinely monitors the groundwater for radiological constituents and reports the results to the NRC. In addition, in 2007, the nuclear power industry began implementing its "Industry Ground Water Protection Initiative" (NEI 2007). The NRC staff has been monitoring implementation of this initiative at licensed nuclear reactor sites since 2008. Results from the "Industry Ground Water Protection Initiative" are reported annually to the NRC.

3.6 Terrestrial Resources

3.6.1 Byron Ecoregion

Beginning in the 1980s, the USGS, EPA, the Commission for Environmental Cooperation (CEC), and various other Federal agencies and interagency groups began delineating North American ecoregions in order to provide a common geographical framework to assess and manage the environment. Ecoregions are divided into Levels I through IV. Level I is the broadest category, while Level IV is the most specific. Ecoregions are delineated by many factors to include location, climate, vegetation, hydrology, terrain, wildlife, and land use. The Byron site lies within the following Level I through IV ecoregions (EPA 2013b):

- Level I: Eastern Temperate Forests,
- Level II: Central USA Plains,
- Level III: Central Corn Belt Plains, and
- Level IV: Illinois/Indiana Prairies.

The Eastern Temperate Forests ecoregion covers the majority of the Eastern States and is characterized as having a moderate to mildly humid climate with dense and diverse forest cover consisting mostly of tall broadleaf, deciduous trees and needle-leaf conifers (CEC 2008). Within the Eastern Temperate Forests, the Central USA Plains is mostly glaciated to rolling plains, with some sand dunes and lake plains (Wiken et al. 2011). Large prairie communities and oak–hickory forests were native to this ecoregion, but have been largely replaced by agriculture. Within these plains, Byron lies in the Central Corn Belt Plains, which occupies 38,000 mi^2 (98,000 km^2) of land, primarily in northern Illinois and the northwestern corner of Indiana.

Gently rolling smooth plains, irregular plains, and shallow stream valleys characterize much of the area (USFS 1996). The native landscape of the ecoregion was composed of bluestem prairie communities and oak–hickory forests, but has mostly been replaced by corn and soybean agriculture. Common wildlife found in the region include white-tailed deer (*Odocoileus virginianus*), coyote (*Canis latrans*), bobcat (*Lynx rufus*), meadow vole (*Microtus pennsylvanicus*), Canada goose (*Branta canadensis*), mallard duck (*Anas platyrhynchos*), black-capped chickadee (*Parus atricapillus*), upland sandpiper (*Bartramia longicauda)*, Illinois mud turtle (*Kinosternon flavescens*), and Illinois chorus frog (*Pseudacris illinoensis*) (Wiken et al. 2011). Agricultural lands are the predominant land cover in the ecoregion at 75.3 percent, followed by developed land (11.6 percent), and forests (9.3 percent). Although developed land is less prominent than agricultural land, from 1973 to 2000, the percent of developed land has increased 2.4 percent, while the percent of agricultural land and forested land has decreased (Karstensen et al. 2013d).

Byron site lies within the Upper Rock River watershed, which occupies 830 mi^2 (2,100 km^2) of the Rock River Hill Country Natural Division (IDNR 2002b). This area is characterized by rolling glaciated topography and a landscape historically dominated by prairie communities (59 percent), oak forests, dry upland forests, and floodplain forests. The Upper Rock River area land cover is now dominated by cropland (52.1 percent), grasslands (25.1 percent), forests (10.4 percent), open water (1.1 percent), and wetlands (1.5 percent) (IDNR 2002b).

3.6.2 Byron Site and Vicinity

The Byron site occupies 1,782 ac (721 ha) immediately east of the Rock River. The main Byron site area, which is where the majority of the plant facilities are located, is approximately 1,398 ac (566 ha) and is surrounded primarily by agricultural fields. Within the main site area, the power block and support facilities (buildings, switchyard, parking lots, and roads) occupy approximately 154 ac (62 ha). Approximately 840 ac (340 ha) are disturbed lands that are leased for agricultural uses, including croplands, pastures, and fallow fields. Forests, meadows, and grasslands occupy the undisturbed portions of the site, which encompass 404 ac (163 ha). The water intake and discharge pipeline and transmission corridor occupy the remaining 384 ac (155 ha) of the site. This corridor extends west from the main site area approximately 2 mi (3.2 km) to the Rock River and is surrounded by primarily wooded lands. (Exelon 2013b)

3.6.2.1 Summary of Past Byron Surveys and Reports

Commonwealth Edison Company conducted site surveys of the Byron site in the fall of 1972, and the winter, spring, and summer of 1973 as part of the construction permit application for Byron Units 1 and 2. Vegetation and wildlife in the transmission and pipeline corridor were surveyed in November 1973. These initial site surveys were used to determine baseline conditions of the terrestrial environment before construction.

In 2006, while developing a biodiversity assessment and wildlife habitat management plan for the Byron site, Exelon staff conducted tours of the site with trained biologists (Starke and Cox 2011). Exelon staff recorded any vegetation, bird species, or other wildlife observed during these tours.

These surveys are the primary sources for describing the terrestrial resources at Byron. To supplement such surveys, the NRC staff conducted an environmental site visit and a desktop review of other natural resource databases and surveys within the vicinity of Byron.

3.6.2.2 Vegetation

Common Vegetation

Byron lies within the Upper Rock River Basin, which covers nearly 6,000 ac (2,428 ha) in northern Illinois and supports approximately 800 native plant species. Prior to the construction of the Byron facilities, 50 percent of the site was agricultural cropland. The northern half of the site was wooded with some cropland, and the southern half was mainly cropland. Approximately 35 percent of the site was grassland and fallow fields, consisting mainly of ragweed (*Ambrosia artemisiifolia*), alfalfa (*Medicago sativa*), and red clover (*Trifolium pretense*) in the fallow fields, and Kentucky bluegrass (*Poa pratensis*), timothy (*Phleum pretense*), and Canada bluegrass (*Poa compressa*) in the grasslands (Exelon 2013a). The remaining 15 percent was forested and consisted primarily of oak (*Quercus* spp.) and hickory (*Carya* spp.) varieties. The transmission and pipeline corridor area was approximately 44 percent (212 ac (86 ha)) cultivated land (mostly cornfields), and approximately 39 percent (189 ac (76 ha)) was forested. The wooded and meadow areas of the Byron site have remained undisturbed since the property was purchased in the 1970s.

Construction of Byron disturbed approximately 538 ac (218 ha), or 30 percent of the existing Byron site. The majority of land on the Byron site is currently agricultural land, with about 300 ac (121 ha) of wooded lands and 150 ac (61 ha) of meadow or grasslands. Currently, 47 percent of the Byron site (840 ac (340 ha)) is leased for agricultural use. This land is considered disturbed because most of it is tilled. The remaining 23 percent (404 ac (163 ha)) of Byron is undisturbed land (Exelon 2013b).

Based on baseline surveys performed by ComEd (1981), Exelon concluded that the dominant tree species on the site are oak (*Quercus* spp.) and hickory (*Carya* spp.) varieties. Common oak varieties recorded during the 2006 tours of the Byron site include black oak (*Q. velutina*), jack oak (*Q. ellipsoidalis*), pin oak (*Q. palustria*), red oak (*Q. rubra*), and white oak (*Q. alba*). Hickory varieties recorded include mockernut hickory (*C. tomentosa*), shagbark hickory (*C. ovate*), and shellbark hickory (*C. laciniosa*). Other common tree assemblages found in both 1973 and 2006 include American elm (*Ulmus americana*), black walnut (*Juglans nigra*), hackberry (*Celtis occidentalis*), and cottonwood (*Populous deltoides*). Understory plants include round-leaf dogwood (*Cornus rugosa*), northern prickly ash (*Zanthoxylum americanum*), and wild grape (*Vitis* spp.) (ComEd 1981; Starke and Cox 2011).

Several invasive species common to Illinois are found on the Byron site. Observed invasive species include bull thistle (*Cirsium vulgare*), chicory (*Cichorium intybus*), giant foxtail (*Setaria faberii*), wild carrot (*Daucus carota*), wild parsnip (*Pastinaca sativa*), and Osage-orange (*Maclura pomifera*) (CISEH 2009; Starke and Cox 2011).

Wetlands

Based on an examination of U.S. Fish and Wildlife Service (FWS) National Wetland Inventory maps, a small presence of wetlands exists on the Byron site. The only occurrence of wetlands on site is less than 5 ac (2 ha), or less than 0.3 percent of the Byron total site area. These freshwater forested/shrub wetlands occur on the north edge of the site's western border, adjacent to the Rock River. FWS (2013d) classifies these wetlands as palustrine, which means that the nontidal wetlands occur in a floodplain and are dominated by trees, shrubs, emergent vegetation, mosses, or lichens. Other characteristics are that the total area of the wetlands does not exceed 8 ha (20 ac), the wetlands do not have an active wave-formed or bedrock shoreline, the wetlands have a depth less than 2 m (6.6 ft) at low water, and have a salinity of less than 0.5 parts per thousand. This wetland is also characterized as being seasonally flooded and created or modified by a manmade barrier or dam, which obstructs the inflow or outflow of water.

Additional wetlands occur within the vicinity (5 mi (8 km)) of Byron, including more freshwater forested and shrub wetlands as well as freshwater emergent wetlands (FWS 2013d). These wetlands primarily occur along the Rock River.

Vegetation Management

Vegetation management at Byron is the responsibility of the Facilities Maintenance Department. Different vegetation management guidelines are followed based on the particular area of the Byron site. For example, the high-security areas both inside and outside the Protected Area around the facility are mowed to a height of 6 in. Outlying areas that are of less significance to plant security are treated to some degree with vegetation maintenance to allow for worker access, but are mowed only about twice a year. The undeveloped areas of the site are typically given vegetation maintenance only in response to special requests (Exelon 2013b).

State-Listed Vegetation

This section discusses plant species protected only by the State, and Section 3.8 discusses those species protected under the Endangered Species Act (ESA) alone or in combination with the State. As discussed in Section 3.1.6, Byron and the inscope transmission lines are located entirely within Ogle County. Table 3–5 identifies the 55 plant species that are considered threatened or endangered by the State of Illinois within Ogle County and Winnebago County. On the Byron site, no State-threatened or endangered species have been observed during the 1973 baseline surveys or while developing the site’s wildlife habitat management plan (ComEd 1981; Starke and Cox 2011).

Table 3–5. State-Listed Plant Species in Ogle County

Scientific Name	Common Name	State of Illinois Status[a]
Amelanchier sanguinea	shadbush	SE
Arctostaphylos uva-ursi	bearberry	SE
Asclepias lanuginosa	wooly milkweed	SE
Aster furcatus	forked aster	ST
Besseya bullii	kitten tails	ST
Betula alleghaniensis	yellow birch	SE
Carex cryptolepis	sedge	SE
Carex echinata	little prickly sedge	SE
Carex woodii	pretty sedge	ST
Castilleja sessiliflora	downy yellow painted cup	SE
Ceanothus herbaceus	redroot	SE
Cornus canadensis	bunchberry	SE
Corydalis sempervirens	pink corydalis	SE
Cyclonaias tuberculata	purple wartyback	ST
Cypripedium acaule	moccasin flower	SE
Dichanthelium boreale	northern panic grass	SE
Equisetum pretense	meadow horsetail	ST
Equisetum sylvaticum	horsetail	SE
Filipendula rubra	queen-of-the-prairie	SE
Gymnocarpium dryopteris	oak fern	SE
Helianthus giganteus	tall sunflower	SE
Lathyrus ochroleucus	pale vetchling	ST
Lespedeza leptostachya	prairie bush clover	SE
Luzula acuminate	hairy woodrush	SE
Lycopodium clavatum	running pine	SE
Lycopodium dendroideum	ground pine	SE
Nothocalais cuspidata	prairie dandelion	SE
Phegopteris connectilis	long beech fern	SE
Sorbus Americana	American mountain ash	SE
Sullivantia sullivantii	Sullivantia	ST
Tomanthera auriculata	ear-leafed foxglove	ST

Scientific Name	Common Name	State of Illinois Status[a]
Trientalis borealis	star-flower	SE
Woodsia ilvensis	rusty woodsia	SE

[a] SE = State-endangered; ST = State-threatened

Source: IDNR 2013

3.6.2.3 Wildlife

Common Wildlife

Byron is in the Upper Rock River Basin, which has a high terrestrial species diversity due to its extensive range of habitats and available vegetation (IDNR 2001). The Byron site provides several types of terrestrial habitats for birds, mammals, and other wildlife. Plant communities and wooded areas along the Rock River shoreline provide an important source of food and refuge for birds. The combination of food, protection, and other resources available make the Upper Rock River Basin and the Byron site an important habitat for many birds and wildlife. In addition, the area is part of the Mississippi flyway and an important stopover location for many migratory birds (Exelon 2013a; IDNR 2002b).

The baseline surveys at the Byron site identified 103 migratory and resident bird species on the site (ComEd 1981). The more recent 2006 wildlife observations indicate a total of 107 bird species (Starke and Cox 2011). Fourteen mammal species were originally identified in the 1973 surveys, with an additional seven species added from more current observations. Only three reptile and amphibian species were observed in 1973, and, since the baseline surveys, seven more species have been added to that list. Table 3–6 describes the most common or abundant birds, mammals, reptiles, and amphibians on the Byron site.

As described in Section 3.2, several important natural areas occur within the vicinity of Byron. As described above, this area is part of the Mississippi flyway, used by migrating birds as important stopover points during long seasonal migrations (FWS 2013f). Species of diving and dabbling ducks, Canada geese, and particularly snow geese (*Chen caerulescens*) use corridors that cross north central Illinois in their migration. High-quality bird habitats within the region surrounding Byron include the Lowden–Miller State Forest and the adjacent Castle Rock State Park. The Audubon Society designates both of these areas as Important Bird Areas (IBAs). Combined, these two areas cover approximately 4,225 ac (1,710 ha) and provide one of the finest bird habitats in Illinois. This large, forested tract of land offers resident and migratory birds protection and is home to more breeding pairs of forest bird species than any other part of Illinois (IDNR 2001). Castle Rock State Park contains some of the most diverse terrestrial habitats in the Upper Rock River area, including ravine forest, upland forest, prairie, river creeks, and sandstone outcrops (IDNR 2002b). The most unique features of the park are mesic upland forest and sandstone cliffs, which provide habitat for relict boreal plants (IDNR 2002b).

Table 3–6. Most Common or Abundant Wildlife on the Byron Site

Birds	
Migratory Birds	
fox sparrow (*Passerella iliaca*)	**slate-colored junco** (*Junco hyemalis)*
golden-crowned kinglet *(Regulus calendula*)	**white-throated sparrow** (*Zonotrichia albicollis)*
Resident Birds	
American crow (*Corvus brachyrhynchos)*	**cedar waxwing** (*Bombycilla cedrorum)*
American goldfinch (*Spinus tristis*)	**robin** (*Turdus migratorius*)
Game Birds	
American woodcock (*Philohela minor*)	**mourning dove** (*Zenaidura macroura*)
bobwhite quail (*Colinus virginianus)*	**ring-necked pheasant** (*Phasianus colchicus*)
gray partridge (*Perdix perdix*)	
Mammals	
common opossum (*Didelphis marsupialis)*	**raccoon** (*Procyon lotor*)
deer mouse (*Peromyscus maniculatus)*	**wood mouse** (*Peromyscus leucopus)*
meadow vole (*Microtus pennsylvanicus*)	
Reptiles and Amphibians	
alligator snapping turtle (*Macroclemys temminckii*)	**garter snake** (*Thamnophis sirtalis*)
American toad (*Bufo americanus*)	**red milk snake** (*Lampropeltis triangulum syspila*)
Bullfrog (*Rana catesbeiana*)	**smooth softshell turtle** (*Apalone mutica*)
Bullsnake (*Pituophis melanoleucus*)	**spring peeper** (*Hyla crucifer*)
eastern hognose snake (*Heterodon platyrhinos*)	**western chorus frog** (*Pseudacris triseriata*)

Sources: Exelon 2013a; Starke and Cox 2011

State-Listed and Other Important Wildlife

This section discusses bird, mammal, and reptile species protected only by the State, the Bald and Golden Eagle Protection Act (BGEPA), and the Migratory Bird Treaty Act (MBTA). Section 3.8 discusses those species protected under the ESA alone or in combination with the State.

Birds

Table 3–7 identifies the four birds that are considered threatened or endangered by the State of Illinois within Ogle County.

Table 3–7. State-Listed Bird Species in Ogle County

Scientific Name	Common Name	State of Illinois Status
	Birds	
Ammodramus henslowii	Henslow's sparrow	Threatened
Bartramia longicauda	upland sandpiper	Endangered
Haliaeetus leucocephalus	bald eagle	Threatened
Lanius ludovicianus	loggerhead shrike	Threatened

Source: IDNR 2013

With the exception of the bald eagle, none of the State-listed bird species presented in Table 3–7 have been observed on the Byron site during the 1973 baseline surveys or while developing the site's wildlife habitat management plan (ComEd 1981; Exelon 2013a; Starke and Cox 2011).

Byron is located approximately 6 mi (10 km) northeast of the Castle Rock State Park and Lowden–Miller State Forest IBA (Exelon 2013b). The Lowden–Miller State Forest and Castle Rock State Park host a variety of rare breeding warblers and other song birds and host nesting populations of several bird species rarely found in Illinois, including the black-throated green warbler (*Setophaga virens*), the cerulean warbler (*S. cerulea*), the hooded warbler (*S. citrina*), the worm-eating warbler (*Helmitheros vermivorum*), the chestnut-sided warbler (*S. pensylvanica*), and the golden-winged warbler (*Vermivora chrysoptera*). The Audubon Society designated this area IBA because it meets the habitat criteria for both the State-listed threatened cerulean warbler and the blue-winged warbler (*V. cyanoptera*) (Audubon 2013).

Species Protected under the Bald and Golden Eagle Protection Act

The Bald and Golden Eagle Protection Act of 1940, as amended (16 U.S.C. § 668–668c) (BGEPA), prohibits anyone from taking bald or golden eagles (*Aquila chrysaetos*), including their nests or eggs, without a permit issued by the FWS. The Act and regulations define the word "take" to include the following: to pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, destroy, molest, or disturb (50 CFR 22.3). The word "disturb" means, among other things, to take action that causes (1) injury to an eagle, or (2) a decrease in its productivity or nest abandonment, by substantially interfering with breeding, feeding, or sheltering behavior (50 CFR 22.3).

Bald eagles have been observed along the banks of the Rock River near the Byron site, as well as other locations along the Rock River and its tributaries (eBird 2013; Exelon 2013a).

Species Protected Under the Migratory Bird Treaty Act

The MBTA of 1918, as amended (16 U.S.C. §§703–712), is administered by the FWS. The Act prohibits anyone from taking native migratory birds, their eggs, feathers, or nests. MBTA regulations define "take" to mean to pursue, hunt, shoot, wound, kill, trap, capture, or collect, or any attempt to carry out those actions (50 CFR 10.12). However, take does not include habitat destruction or alteration. All Illinois State listed species shown in Table 3–7 are protected under the MBTA.

Mammals

Table 3–8 identifies the nine mammals that are considered threatened or endangered by the State of Illinois.

Table 3–8. State-Listed Mammal Species in Illinois

Scientific Name	Common Name	State of Illinois Status
	Mammals	
Canis lupus	gray/timber wolf	Threatened
Corynorhinus rafinesquii	Rafinesque's big-eared bat	Endangered
Myotis austroriparius	southeastern myotis	Endangered
Myotis grisescens	gray bat	Endangered
Myotis sodalist	Indiana bat	Endangered
Neotoma floridana	eastern woodrat	Endangered
Ochrotomys nuttali	golden mouse	Threatened
Oryzomys palustris	rice rat	Threatened
Spermophilus franklinii	Franklin's ground squirrel	Threatened

Source: IESPB 2011

None of the State-listed mammals reported in Table 3–8 above have been reported on or near the Byron site (Exelon 2013a; Starke and Cox 2011).

Reptiles and Amphibians

Table 3–9 identifies the two reptiles and one amphibian that are considered threatened or endangered by the State of Illinois.

Table 3–9. State-Listed Reptile and Amphibian Species in Ogle County

Scientific Name	Common Name State-Listed Reptile and Amphibian Species in Ogle County	State of Illinois Status
	Reptiles	
Equisetum pretense	Blanding's turtle	Threatened
Hemidactylium scutatum	four-toed salamander	Threatened
Heterodon nasicus	western hognose snake	Threatened

Source: IDNR 2013

None of the State-listed species reported in Table 3–9 above have been reported on or near the Byron site during the 1973 baseline surveys or while developing the site's wildlife habitat management plan (Exelon 2013a; Starke and Cox 2011).

3.6.3 Transmission Line Corridors

Section 3.1.6.5 describes the inscope transmission lines, which are limited to those transmission lines that connect the nuclear plant to the switchyard where electricity is fed in to the regional distribution system (NRC 2013a). For Byron, the onsite 345-kV station switchyard serves this purpose (Exelon 2013b). The switchyards are adjacent to Units 1 and 2 and within the boundary of the Byron site (see Figure 3–3). Therefore, the above discussion of the affected terrestrial environment for the Byron site is representative of the affected environment for the inscope transmission lines.

3.6.4 WHC Wildlife at Work Program

The Wildlife Habitat Council (WHC) Wildlife at Work Program provides a structure for corporations to implement voluntary conservation efforts that exceed regulatory requirements (WHC 2014). These habitat projects can vary in size and scope and emphasize community involvement and collaboration.

Exelon (a WHC member since 2005) established a Wildlife at Work Program at Byron with the mission of increasing biodiversity at the Byron site. The program focuses on the management and monitoring of individual onsite habitat projects. The program at Byron is managed by the Byron Environmental Stewardship Team, which has up to 25 members (Starke and Cox 2011).

There are several ongoing projects that are part of Byron's Wildlife at Work Program. First is the enhancement of habitats for cavity-nesting birds, which provides houses for local birds in need of nesting areas. According to Exelon's monitoring of this project, the bird houses located in meadows and wooded areas on the Byron property have been successful in encouraging bluebirds (*Sialia sialis*) and wood ducks (*Aix sponsa*) to utilize the habitats present at Byron (Exelon 2011b). An increase in the number of bluebirds has been observed in the project area, along with an increase in the number of houses with chicks that have fledged. The number of wood duck houses with ducklings has also increased (Starke and Cox 2011).

The second project is the enhancement of habitats for bats, which provides houses for local bat species. This project began in 2007 after Byron personnel noticed bats roosting under an awning on one of the main facility buildings. The bat houses were constructed to encourage the bats to roost nearer to the Rock River where there is a more abundant food supply of insects for the bats. Although deposits found on the foliage below the bat houses suggest the presence of bats, relatively few observations of bats using the houses have been made. Also, no observations or surveys have been conducted using trained biologists to determine the species of bat present on the site (Exelon 2013b; Starke and Cox 2011).

The third ongoing project on site is a butterfly garden, which provides food and cover for a variety of different species. The garden was established outside the training building and has proven very successful in attracting different pollinators, birds, and butterflies. According to Exelon, employees and visitors to the Byron site have had a very positive reaction to this project in particular (Starke and Cox 2011).

As part of the Wildlife at Work program, Exelon plans to continue to maintain and monitor existing bird and bat houses, as well as the butterfly garden. Future potential projects being discussed include the installation of heron platforms along the Rock River, the creation of retention ponds on the property where birds and animals would have increased access to water, and the possible addition of prairie plant habitat on the Byron property (Starke and Cox 2011).

3.7 Aquatic Resources

Rock River

The Byron site is located 2 mi (3.2 km) east of the Rock River from which the facility withdrawals and discharges cooling system make-up and blowdown water. From its source in the Horicon Marsh in Dodge County, Wisconsin, the Rock River meanders south to the Wisconsin–Illinois state line and then southwest through Illinois to its confluence with the Mississippi River at Rock Island, Illinois. The river flows a total length of 318 mi (512 km). The river's watershed covers an area of approximately 28,270 km^2 (10,915 mi^2, 6,985,600 ac, or 2,826,972 ha), of which 14,633 km^2 (5,650 mi^2, 3,616,000 ac, or 1,463,343 ha) are in Illinois. The primary land use within the Rock River basin is agricultural. The largest tributaries are the Pecatonica, the Kishwaukee, and the Green Rivers (Sinclair 1996).

The IDNR has designated the lower Rock River basin, which includes Ogle County and eight other Illinois counties, as a Resource Rich Area (Suloway et al. 1996). However, the lower basin is highly disturbed: in 2006, the IEPA reported that only about 412 ac (167 ha) of undegraded, high-quality natural habitat remained in this basin (IEPA 2006). Industrial point source discharge, agricultural runoff, and urbanization are the major sources of Rock River water quality degradation. Channelization beginning in the early 1900s, the installation of seven in-channel dams, and the drainage of wetlands have also reduced the quantity and quality of aquatic habitat in the basin (Sinclair 1996). The closest dam to Byron lies in Oregon, Illinois, approximately 8.0 km (5.0 mi) downstream of the Byron discharge (Exelon 2013a).

Aquatic Surveys and Monitoring

Prior to Byron construction and operation, ComEd commissioned Environmental Analysts, Inc. (EAI) to perform baseline monitoring of phytoplankton, zooplankton, benthic macroinvertebrate, and fish communities in the Rock River between 1972 and 1985 for the following sample periods: 1972 to 1974, 1975 to 1979, and 1983 to 1985. ComEd presented the baseline monitoring results from the 1972-to-1973 sampling year in its ER for Byron construction and the results from the 1973-to-1974 sampling year in its ER for Byron operation (ER-O) (ComEd 1981). The NRC also provided brief summaries of the results of these studies in its Final Environmental Statements for Byron construction (FES-C) (AEC 1974) and operation (FES-O) (NRC 1982).

Following the commencement of Byron operation (Unit 1 in September 1985; Unit 2 in August 1987), aquatic surveys of fish and benthos continued from 1986 through 2002 and in 2011. Exelon commissioned EA Engineering, Science, and Technology (EA Engineering, successor to EAI) to perform the 2011 survey (EA Engineering 2012) in support of the preparation of Exelon's license renewal application. All of the preoperational and operational studies collected samples at the same locations: five transects in the Rock River (from a point 2.4 mi (3.9 km) upstream of Byron, Illinois, to just upstream of the dam at Oregon, Illinois) and at the mouths of six tributary streams that flow into the Rock River near the Byron site (Stillman Creek, Mill Creek, Woodland Creek, Leaf River, Spring Creek, and Silver Creek). Table 3–10 lists and describes these locations, and Figure 3–12 illustrates the sampling locations.

In 1986 and 1987, biologists from the Illinois Natural History Survey (INHS) surveyed fish in the Rock River near Castle Rock State Park as well as in three nearby tributary streams to support an IDOT road improvement project (Wetzel et al. 1998). Although this study was unrelated to Byron, the study site was located approximately 10 mi (16 km) downstream of the Byron discharge.

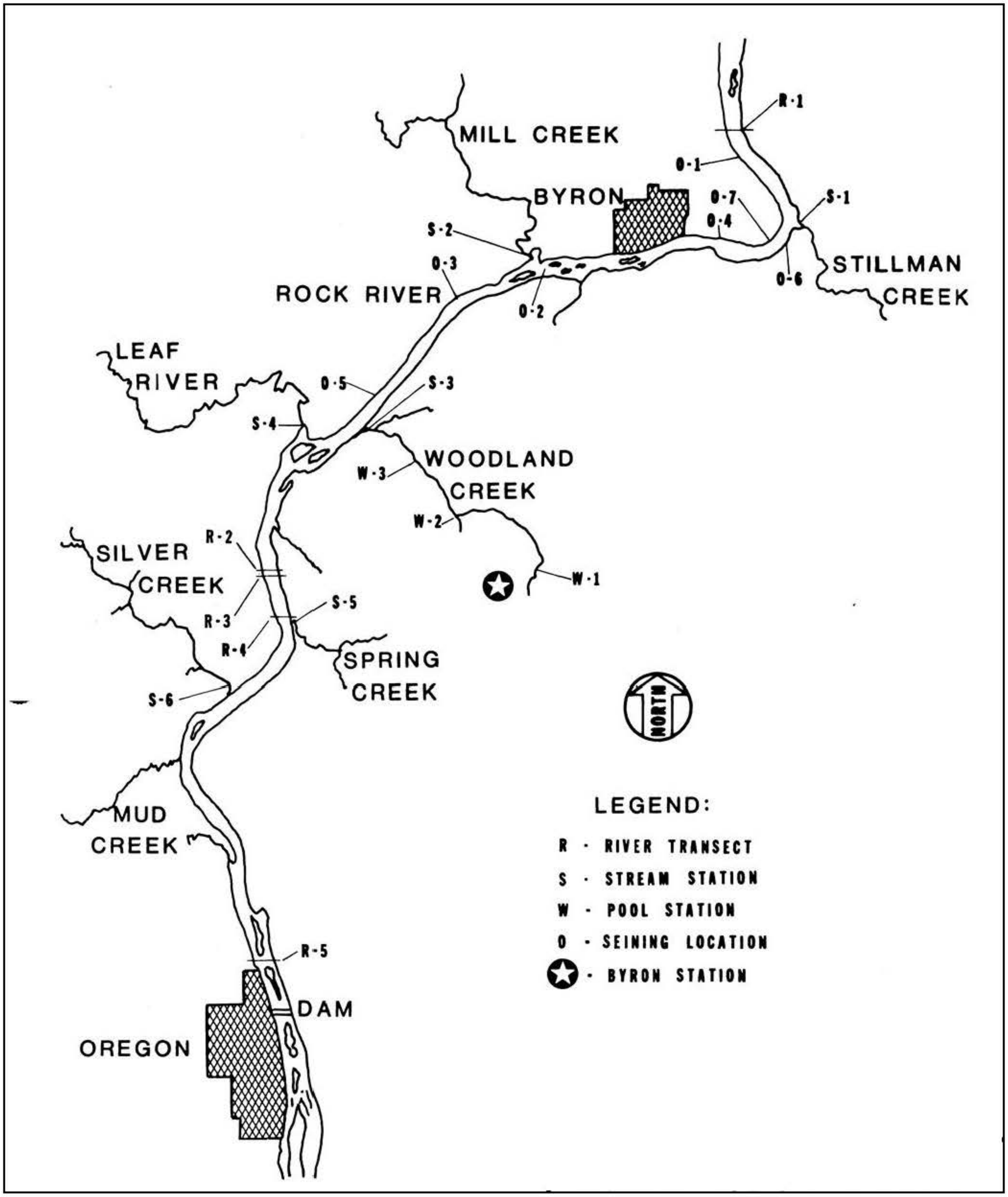
Table 3–10. Sampling Locations for Preoperational and Operational Aquatic Monitoring and Surveys of the Rock River

Location	Description
	Rock River Transects
R-1	2.4 mi (3.9 km) upstream of Byron, IL; represents conditions well above (upriver of) the Byron intake
R-2	300 yd (270 m) upstream of the blowdown discharge point; represents conditions in the vicinity of the Byron intake
R-3	at the Byron blowdown discharge point
R-4	0.7 mi (1.1 km) downstream of the blowdown discharge point; represents conditions inclusive of Byron's thermal plume
R-5	3.4 mi (5.5 km) downstream of Byron and 1,000 yd (910 m) above the dam at Oregon, IL; represents conditions well below (downriver of) Byron
	Tributaries
S-1	Stillman Creek
S-2	Mill Creek
S-3	Woodland Creek (this creek was sampled at three pool locations: W-1, W-2, and W-3)
S-4	Leaf River
S-5	Spring Creek
S-6	Silver Creek

Source: ComEd 1981

In 1993, ComEd commissioned Ecological Specialists, Inc. (ESI), to conduct a mussel study within the Rock River near the Byron intake and discharge points. Exelon commissioned ESI to repeat this survey in 2011 (ESI 2011) in support of the preparation of Exelon's license renewal application.

Figure 3–12. Rock River Aquatic Survey Sampling Locations



Source: ComEd 1981, Figure 2.2-1

The following sections characterize the aquatic communities in the vicinity of Byron by summarizing the results of the available studies.

Phytoplankton

EAI conducted the first phytoplankton survey near the Byron site on 15 sample days between May 1972 and June 1973 at five river transection locations (R-1 through R-5) and at three tributary mouths (S-3, S-4, and S-5) by immersing several 1-L (liter) polypropylene bottles beneath the surface of the water. The FES-C (AEC 1974) provides a brief summary of the first sample year. The FES-C states that between 7 and 37 phytoplankton species were identified on each sample day, and the biovolume of each sample ranged from less than 1 microliter per liter (μL/L) in winter to over 40 μL/L in late summer. A group of about eight centric diatom species dominated the samples by biomass and were those typical of the upper Mississippi River Basin (which includes the Rock River Basin), including: *Melosira ambigua*, *Stephanodiocus hantzchii*, *S. niagarae*, *S. astraea minutula*, and *Cyclotella meneghiniana*. Green, blue--green, and euglenoid algae were of localized abundance on certain sample days and were very rare during the colder months. Filamentous blue-green algae were most abundant in September and August. The FES-C concluded that the Rock River in the vicinity of the Byron site is a moderately eutrophic stream with planktonic flora normal for the region.

In the second sample year (September 1973 through October 1974), EAI surveyed phytoplankton at four of the five river transection locations (R-2 through R-5) and at the mouths of two tributaries (S-4 and S-5) on 6 sample days. ComEd (1981) reported the results of this sample year in its ER-O. The survey yielded a total of 119 taxa, which included 59 diatoms (comprising 93.7 percent of all collected phytoplankton), 43 green algae (3.3 percent), 9 blue-green algae (2.4 percent), 4 euglenids (0.1 percent), 2 dinoflagellates (less than 0.1 percent), 1 golden algae (0.5 percent), and 1 cryptomonad (less than 0.1 percent). The same diatom species dominated the samples by biomass as those in the first sample year with the additional mention of *M. granulata*, *M. granulata* var. *angustissima*, *S. minutus*, *S. subtilus*, and *Nitzschia palea* as frequently collected species.

Zooplankton

EAI conducted a zooplankton survey on 19 sample days between April 1972 and June 1973 at five river transection locations (R-1 through R--5) and at three tributary mouths (S-3, S-4, and S-5) by pouring 60 L (20 gal) of surface water through a #20 mesh plankton net. The FES-C (AEC 1974) provides a brief summary of the first sample year. The FES-C states that EAI collected 38 rotifer species and 31 protozoan species. Of these, 7 rotifers and 5 protozoa occurred on more than two-thirds of sample days. Rotifers in the genera *Keratella*, *Polyarthra*, and *Brachionus* and protozoa in the genera *Centropyxis*, *Difflugia*, and *Vorticella* were most common. One species of copepod (*Cyclops bicuspidatus*) was also frequently collected. Zooplankton were most abundant in spring and fall samples and least abundant in summer and winter samples.

In the second sample year (September 1973 through October 1974), EAI surveyed the same sampling locations as in the previous sample year, but on fewer occasions (6 sample days). ComEd (1981) reported the results of the second sample year in its ER-O. The survey collected 18 rotifer species, 14 protozoan species, 7 cladoceran species, 3 copepod species, 2 tardigrade species, as well as unspecified nematodes, oligochaetes, and chironomids. As in the first sample year, rotifers were the numerically dominant taxa at both Rock River and tributary sampling locations. The most commonly occurring forms included the juvenile copepod stages (nauplii and copepodites), the cladocerans *Bosmina* and *Chydorus*, and the rotifer genera *Brachionus*, *Keratella*, and *Synchaeta*. Zooplankton samples exhibited summer and winter lows and spring and fall peaks ranging from 2 organisms per L (R-2, January 1974) to 350 organisms per L (R-2, April 1974), which corresponded to abundance measurements during the first sample year.

Periphyton Artificial Substrate Samplers

Information on the first year of periphyton sampling was not included in the FES-C (AEC 1974); therefore, only the sampling results from the second sample year are discussed below. ComEd's ER-O (1981) notes that periphyton data collected during the second sample year did not deviate markedly from the information collected during the corresponding seasons of the first sample year.

EAI sampled periphyton with artificial substrate samplers at the five river stations (R-1 through R-5), four tributary stream stations (S-3, S-4, and S-5 from September through December 1973, and S-3, S-5, and S-6 from January through September 1974), and two Woodland Creek pool stations (W-1 and W-2) from September 1973 through September 1974. A total of 266 algae taxa were identified from all samples, which included 181 diatoms, 64 green algae, 1 golden algae, 12 blue-green algae, 7 euglenids, and 1 dinoflagellate. Diatoms dominated the samples, and the most commonly collected forms included *Melosira ambigua*, *M. granulata* var. *angustissima*, *Nitzschia linearis*, *Navicula viridula* var. *avenacea*, *Gomphonema olivaceum*, and *G. parvulum*, all of which are commonly found in eutrophic waters.

Zoobenthos

The FES-C (AEC 1974) indicates that EAI sampled zoobenthos on 7 days between May 1972 and June 1973. Samples were dominated by four groups of invertebrates: oligochaete worms (family Tubuficidae, 9 taxa, 147.3 organisms per square meter (m^2)), mayfly larvae (order Ephemeroptera, 5 taxa, 9.6/m^2), caddisfly larvae (order Trichoptera, 2 taxa, 15.7/m^2), and midge fly larvae (family Chironomidae, 21 taxa; 20.1/m^2). Caddis fly and mayfly larvae numbers were lower in fall, which correlates with the time during which mature larvae would emerge from the stream.

ComEd's ER-O (1981) provides more detailed information on zoobenthos collected during the second sample year (1973 to 1974). EAI collected PONAR dredge samples on 6 sample days between September 1973 and October 1974 at river sampling locations R-1 through R-5 and tributary locations S-3, S-5, W-1, and W-3. These locations included a variety of substrate types. Samples containing coarse gravel supported the greatest number of invertebrate taxa (93), followed by samples containing sand (77 taxa), fine gravel (43 taxa), silt (40 taxa), muck (40 taxa), fine rubble (17 axa), detritus (11 taxa), and mollusk shells (3 taxa). The same four groups of invertebrates dominated the second year samples as those that dominated the first year. However, midge fly larvae were the most prevalent taxa in the second year. Samples also included two species of family Naididae (aquatic worms), two species of leeches (class Hirudinea), five genera of dragonflies (order Odonata), nine genera of beetles (order Coleoptera), true flies (order Diptera), flatworms (class Turbellaria), roundworms (phylum Nematoda), and water mites (subclass Acari).

Ichthyoplankton

The FES-C (AEC 1974) and FES-O (NRC 1982) indicate that ichthyoplankton (fish eggs and larvae) densities were very low at Rock River sampling locations during preoperational surveys (one egg or larvae per 100 cubic meters (m^3) (3,500 cubic feet (ft^3))) in 1972 to 1973 and six larvae per 100 m^3 (3,500 ft^3) in 1973 to 1974). Ichthyoplankton densities were higher at tributary sampling locations, which the FES-O attributed to washout from spawning sites. In 1973, three sampled streams averaged a density of 288 eggs or larvae per 100 m^3 (3,500 ft^3). Larvae of minnows (family Cyprinidae), suckers (family Catastomidae), bullhead catfishes (family Ictaluridae), and sunfishes (family Centrarchidae) were the most commonly collected.

Mussels

In 2009, Bales et al. (2012) surveyed mussels at 36 sites in the Rock River and its tributaries by hand grabbing and visual detection when water conditions permitted. The survey found 27 extant species across the river basin. The pimpleback (*Quadrula pustulosa*) occurred at all mainstem sample sites, and the plain pocketbook (*Lampsilis cardium*), fragile papershell (*Leptodea fragilis*), State-threatened black sandshell (*Ligumia recta*), Wabash pigtoe (*Fusconaia flava*), and pink papershell (*Potamilus ohiensis*) were also commonly occurring species at the majority (50 to 86 percent) of sites. One of the sample sites was 1 mi (1.6 km) downstream of Byron (Site No. 4). This site yielded eight species with live individuals (L) or fresh dead shells (FD): paper pondshell (*Utterbackia imbecillis*, 1 L), Wabash pigtoe (3 L), pimpleback (23 L), plain pocketbook (15 L), fragile papershell (unspecified number of FD), black sandshell (1 L), pink papershell (1 L), and lilliput (*Toxolasma parvum*, 1 L).

The first mussel survey in the direct vicinity of the Byron site was conducted in 1993 by ESI to determine if mussels would be affected by the construction of sediment control structures. During that study, ESI collected 21 species of mussels, 7 of which were only collected as weathered shells.

In 2011, ESI (2011) repeated the 1993 survey along 25 100-m (330-ft) transects that ran perpendicular to the bank starting 800 m (0.5 mi) upstream of the Byron discharge and continuing at 100-m (330-ft) intervals to a point 1,600 m (1 mi) downstream of the discharge. For each sample, a diver searched each transect line for a minimum of 3 minutes and collected all mussels encountered within 1 m (3.2 ft) of the line. Several quantitative and qualitative samples were also collected within areas of mussel concentrations to estimate density and species richness.

A total of 21 species were collected during the study, only 8 of which were collected as live individuals. Pimpleback (93.1 percent of individuals collected) overwhelmingly dominated the live samples, followed by plain pocketbook (4.1 percent) and Wabash pigtoe (1.0 percent). The remaining live species were fatmucket clam (*Lampsilis siliquoidea*, 0.5 percent), fragile papershell (0.5 percent), round pigtoe (*Pleurobema sintoxia*, 0.3 percent), white heelsplitter (*Lasmigona complanata complanata*, 0.3 percent), and pink papershell (0.2 percent). No Illinois-protected species were collected alive, although ESI collected weathered shells of four species: purple wartyback (*Cyclonaias tuberculata*, State-threatened), spike (*Elliptio dilatata*, State-threatened), sheepnose (*Plethobasus cyphyus*, State-endangered), and black sandshell (State-threatened). The butterfly mussel (*Ellipsaria lineolata*, State-threatened) was collected as a subfossil shell.

Mussel density was relatively high (12.0 individuals per 1 m^2 (11 square feet)). Mussels were most abundant within the transition zone between cobble/gravel/sand substrate and sand substrate. The average number of mussels was also significantly higher along the east bank (1.5 individuals per 10 by 1 m (32 by 3.2 ft) section) than along the west bank (0.6 individuals/section). Mussels were also more abundant upstream (1.8 individuals/section) of Byron than downstream (0.5 individuals/section). ESI determined that this was not temperature related, because the thermal plume was limited to an area near the west bank and mussel densities abundance in semiquantitative samples did not differ significantly between upstream and downstream locations along that bank. Samples were composed of both young and old individuals, and half of the individuals collected were over 5 years old. Only 3.2 percent of mussels collected were fresh dead shells, which indicates that the community has a low mortality rate.

As a result of the 2011 study, ESI concluded that while species richness declined between the 1993 and 2011 study, a level-of-effort comparison between the two studies indicated that species abundance increased. Both studies yielded the most individuals in a thin strip of transitional substrate along the east bank, and more individuals occurred upstream than downstream.

Fish

Beginning in 1972, EAI surveyed the Rock River fish community near Byron at the five river sampling locations (R-1 through R-5) and at the mouths of the tributary streams listed in Table 3–10. The results of the first sample year (1972 to 1973) were not reported in the FES-C (AEC 1974), but some of the results of the first year are summarized in ComEd's ER-O (1981). Its ER-O also describes the results of the second sample year (1973 to 1974).

EAI conducted fish samples with seines and by electrofishing. Seine samples were collected with 10-ft and 50-ft beach seines with 1/4-in. mesh. Electrofishing was conducted with a 230-volt, 2,000-watt, 3-phase AC generator for 15 minutes on each side of the river at each of the river stations. Beginning in 1974, hoop nets were also used to sample fish. EAI collected 42 species representing 8 families in the first sample year (1972 to 1973) and 31 species in 8 families in the second sample year (1973 to 1974). The 1972-to-1973 surveys included a greater variety of minnows (*Pimephales* spp.), catfishes, and sunfishes (*Lepomis* spp.), while the 1973-to-1974 surveys collected greater numbers of carpsuckers (*Carpiodes* spp., 40.2 percent of individuals collected) and channel catfish (*Ictalurus punctatus*, 19.1 percent). ComEd (1981) attributed this shift in collected species on changes in gear type (hoop nets beginning in 1974) and effort (decrease in seining effort in several shallow areas in the second sample year). Channel catfish dominated the game species collected in 1973 to 1974; 14 species of game fish were collected, which accounted for over 30 percent of total fish collected, and 62 percent of these were channel catfish. The baselines studies found no significant difference in the abundance or diversity of fish caught at the different sampling locations. Table 3–11 lists the species collected during the 1973-to-1974 sample year and relative abundance of each.

Preoperational monitoring continued until Byron began operating in 1985. The FES-O (NRC 1982) provides limited information about the results of monitoring between 1975 and 1982, when the FES-O was published. Between 1975 and 1979, an additional eight species of fish were collected that had not appeared in the first or second sample years. Channel catfish continued to be the most abundant game fish collected in 1975 to 1976 and 1976 to 1977; bluegill (*Lepomis macrochirus*) was the most abundant game species collected from 1977 to 1978; and black crappie (*Pomoxis nigromaculatus*) was most abundant in 1978-to-1979 and 1979-to-1980 collections.

In 1986 and 1987, biologists from INHS conducted fish surveys in Rock River adjacent to Castle Rock State Park, which lies approximately 10 mi (16 km) downstream of the Byron discharge, as well as in three tributary streams, to support an IDOT road improvement project (Wetzel et al. 1988). Within the Rock River, INHS biologists collected minnow seine and bag seine samples on September 4, 1986, in two narrow reaches of the river in waters of 0 to 5 ft (0 to 1.5 m). The minnow seines were 4 by 10 ft (1.2 by 3.0 m) in size with 1/4-in. mesh. Biologists took at least 10 hauls per site and continued sampling at each site until no additional species were collected. Bag seines were 4 by 30 ft (1.2 by 9.1 m) in size with 1/4-in. mesh. Biologists also continued bag seine sampling until no additional species were collected.

Table 3–11. Fish Species Collected in the Vicinity of Byron During EAI Baseline Monitoring, 1973–1974

Species	Common Name	No. Individuals Collected [(a)]			Relative Abundance (% Collected)
		Rock River	Tributaries	Total	
Catostomidae	**Suckers**	**313**	**232**	**545**	**49.5**
Carpiodes carpio	river carpsucker	157	118	275	25.0
Carpiodes cyprinus	quillback carpsucker	76	92	168	15.2
Moxostoma macrolepidotum	northern redhorse	53	9	62	5.6
Catostomas commersoni	white sucker	22	11	33	3.0
Ictiobus cyprinellus	bigmouth buffalo	3	0	3	0.3
Moxostoma spp.	redhorse spp.	2	0	2	0.2
Hypentelium nigricans	hog sucker	0	1	1	0.1
Ictiobus bubalus	smallmouth buffalo	0	1	1	0.1
Cyprinidae	**Minnows**	**161**	**52**	**213**	**19.3**
Cyprinus carpio	carp	104	39	143	13.0
Notropis atherinoides	emerald shiner	40	6	46	4.2
Pimephales vigilax	bullhead minnow	8	3	11	1.0
Pimephales notatus	bluntnose minnow	5	1	6	0.5
Semotilus atromaculatus	creek chub	2	0	2	0.2
Notropis stramineus	sand shiner	0	2	2	0.2
Carassius auratus	goldfish	1	0	1	0.1
Hybopsis storeriana	silver chub	1	0	1	0.1
Notropis spilopterus	spottail shiner	0	1	1	0.1
Ictaluridae	**Bullhead Catfishes**	**207**	**4**	**211**	**19.2**
Ictalurus punctatus	channel catfish	206	4	210	19.1
Ictalurus melas	black bullhead	1	0	1	0.1
Centrarchidae	**Sunfishes**	**84**	**29**	**113**	**10.3**
Pomoxis nigromaculatus	black crappie	38	9	47	4.3
Pomoxis annularis	white crappie	28	7	35	3.2
Lepomis macrochirus	bluegill	8	8	16	1.5
Micropterus salmoides	largemouth bass	5	3	8	0.7
Micropterus dolomieu	smallmouth bass	2	1	3	0.3
Lepomis humilis	orangespotted sunfish	2	1	3	0.3

Species	Common Name	No. Individuals Collected [a]			Relative Abundance (% Collected)
		Rock River	Tributaries	Total	
Lepomis cyanellus	green sunfish	1	0	1	0.1
Moronidae	**Temperate Basses**	**8**	**0**	**8**	**0.7**
Morone chrysops	white bass	6	0	6	0.5
Morone mississippiensis	yellow bass	2	0	2	0.2
Percidae	**Perches**	**3**	**3**	**6**	**0.6**
Etheostoma nigrum	johnny darter	2	2	4	0.4
Stizostedion vitreum	walleye	1	1	2	0.2
Esocidae	**Pikes**	**1**	**4**	**5**	**0.5**
Esox Lucius	northern pike	1	4	5	0.5
Sciaenidae	**Drums**	**1**	**0**	**1**	**0.1**
Aplodinotus grunniens	freshwater drum	1	0	1	0.1
TOTAL		**778**	**324**	**1,102**	**100.0**

[a] Samples collected from Rock River sample locations R-1, R-2, R-3, R-4, and R-5; Woodland Creek (S-3); Leaf River (S-4); Spring Creek (S-5); and Silver Creek (S-6). Species arranged by number collected.

Source: ComEd 1981

In total, INHS collected 37 species of fish representing 8 families and 24 genera, of which 25 species representing 7 families and 16 genera were collected from two sampling transects in the Rock River. Cyprinids were most commonly collected. Spotfin shiner (*Cyprinella spilopterus*), which accounted for 63.1 percent of fish collected in the river, was the most prevalent cyprinid, followed by bullhead minnow (*Pimephales vigilax*, 7.1 percent), bluntnose minnow (*Pimephales notatus*, 6.9 percent), and striped shiner (*Luxilus chrysocephalus*, 5.8 percent). Game fishes were less commonly collected than would be expected: black crappie, largemouth bass (*Micropterus salmoides*), and bluegill accounted for 3.9, 1.2, and 1.1 percent of Rock River collections, respectively. The low collection frequency of these species was likely due to sampling gear. Seines are only effective in shallow areas with relatively flat bottoms. Electrofishing or a mix of sampling gear designed for a wider variety of microhabitats may have returned a more diverse and representative collection of fish. Thus, while the INHS study indicates certain species' presence, it does not necessarily accurately account for those species' abundance. One State-listed threatened species was collected during this survey: a single gravel chub (*Erimystax x-punctatus*). Table 3–12 lists all species collected in the Rock River during the INHS study.

Table 3–12. Fish Species Collected Downstream of Byron During INHS Study, 1986–1987

		Individuals Collected at Rock River Sampling Locations [a]	
Species	**Common Name**	**Number**	**Percent (%)**
Cyprinella spiloptera	spotfin shiner	358	63.1
Pimephales vigilax	bullhead minnow	40	7.1
Pimephales notatus	bluntnose minnow	39	6.9
Luxilus chrysocephalus	striped shiner	33	5.8
Pomoxis nigromaculatus	black crappie	22	3.9
Notropis stramineus	sand shiner	17	3.0
Notropis hudsonius	spottail shiner	11	1.9
Micropterus salmoides	largemouth bass	7	1.2
Lepomis macrochirus	bluegill	6	1.1
Etheostoma zonale	banded darter	6	1.1
Notropis flavus	stonecat	4	0.7
Lepomis humilis	orangespotted sunfish	4	0.7
Stizostedion vitreum	walleye	4	0.7
Esox Lucius	northern pike	3	0.5
Percina phoxocephala	slenderhead darter	2	0.4
Etheostoma nigrum	johnny darter	2	0.4
Nocomis biguttatus	hornyhead chub	1	0.2
Erimystax x-punctata	gravel chub	1	0.2
Pimephales promelas	fathead minnow	1	0.2
Carpiodes cyprinus	quillback	1	0.2
Moxostoma erythrurum	golden redhorse	1	0.2
Moxostoma macrolepidotum	northern redhorse	1	0.2
Pylodictis olivaris	flathead catfish	1	0.2
Labidesthes sicculus	brook silverside	1	0.2
Lepomis cyanellus	green sunfish	1	0.2
	TOTAL	**567**	**100**

[a] Species arranged by number collected.

Source: Wetzel et al. 1988

In August 2011, EA Engineering (2012) conducted electrofishing and seine samples at River locations R-2, R-3, R-4, and R-5 and at the mouth of Spring Creek (S-5). Each transect was sampled on the east bank (L) and west bank (R) and results were reported in terms of both sampling transect and bank (i.e., R-1L, R-1R, R-2L, R-2R, etc.). Fish were collected by both electrofishing and seining on August 29 and 30. Electrofishing was conducted using a boat-mounted boom-type electrofishing system for 30-minute durations in a downstream direction. Seining was conducted with seines 25 by 6 ft (7.6 by 1.8 m) in size with 3/16-in. ace mesh along 15-m (49.2-ft) transects of shoreline in a downstream direction. Seining and electrofishing were conducted on different days to avoid bias.

EA Engineering collected a total of 2,577 fish (1,794 individuals with seines and 783 individuals with electrofishing gear) of 28 species representing 10 families during the study. While seining collected the most individuals, electrofishing collected a more diverse sample that appears to better represent the fish community near Byron. As in the previous studies near Byron, cyprinids accounted for the overwhelming majority of individuals collected, with spotfin shiner and bullhead minnow being particularly abundant (accounting for 40.2 and 25.0 percent of the total individuals collected, respectively) and sand shiner (*Notropis stramineus*) and bluntnose minnow being relatively common at 8.3 and 4.2 percent, respectively. Collected sport fish included smallmouth bass (*Micropterus dolomieu*, 4.0 percent), channel catfish (1.4 percent), and largemouth bass (0.8 percent). Gizzard shad (*Dorosoma cepedianum*, 4.9 percent) and freshwater drum (*Aplodinotus grunniens*, 3.8 percent) were also relatively common. The remaining 18 species each accounted for less than 2 percent of collected individuals (see Table 3–13). No State-listed endangered or threatened fish were collected during this study.

During electrofishing samples, sampling location R-3R (along the west bank of the Rock River upstream of Byron's discharge) yielded the highest number of fish (234 individuals), while the lowest numbers were collected at the mouth of Spring Creek (S-5, 64 individuals) and along the east river bank upstream of the discharge point (R-2L, 67 individuals). Similar numbers were collected at the remaining sample locations (87 to 89 fish). Species composition ranged from 12 taxa (R-2R) to 17 taxa (R-3R, R-4L). Seven species—gizzard shad, spotfin shiner, bullhead minnow, channel catfish, green sunfish (*Lepomis cyanellus*), smallmouth bass, and freshwater drum—were collected at each of the seven sampling locations. The mean catch per effort (CPE) for fish collected at all sampling locations was 224.0 fish/hour (fish/hr). Mean CPE for sampling locations upstream of the Byron discharge (R-2L, R-2R) was 154 fish/hr, while mean CPE at downstream locations (R-3L, R-3R, R-4L, R-4R, S-5) was 251.6 fish/hr. The CPE was higher along the east river bank ("L" sample locations), on which Byron is located, which was mainly due to higher catches of spotfin shiner and bullhead minnow at these locations.

During the seine samples, the most fish (965 individuals) were collected along the east river bank near the discharge (R-3L), and the fewest number of fish (24) were collected along the west river bank near the discharge (R-3R). Species composition ranged from 6 taxa along the east bank upstream of the discharge (R-2L) and along the east bank downstream of the discharge (R-4L) to 10 taxa along the west bank upstream of the discharge (R-2R) and along the east bank near the discharge (R-3L). Four species—spotfin shiner, bluntnose minnow, bullhead minnow, and smallmouth bass—were collected at each of the seven sampling locations, and one species—sand shiner—was collected at six locations.

Table 3–13. Fish Species Collected in the Vicinity of Byron During EA Engineering Survey, 2011

Species	Common Name	Individuals Collected [a]			
		Electrofishing	Seine	Combined	Percent (%)
Cyprinella spiloptera	spotfin shiner	148	889	1,037	40.2
Pimephales vigilax	bullhead minnow	103	540	643	25.0
Notropis stramineus	sand shiner	24	189	213	8.3
Dorosoma cepedianum	gizzard shad	108	17	125	4.9
Pimephales notatus	bluntnose minnow	28	81	109	4.2
Micropterus dolomieu	smallmouth bass	82	20	102	4.0
Aplodinotus grunniens	freshwater drum	99	0	99	3.8
Lepomis huxnilis	bluegill	33	14	47	1.8
Notropis atherinoides	emerald shiner	20	17	37	1.4
Ictalurus punctatus	channel catfish	28	9	37	1.4
Lepornis cyanellus	green sunfish	28	0	28	1.1
Micropterus salrnoides	largemouth bass	18	3	21	0.8
Carpiodes cyprinus	quillback	12	0	12	0.5
Moxostorna anisuruin	silver redhorse	12	0	12	0.5
Cyprinus carpio	common carp	10	1	11	0.4
Carpiodes spp. and/or *Ictiobus* spp.	Ictiobinae spp.	0	7	7	0.3
Moxostoma macrolepidotum	shorthead redhorse	6	0	6	0.2
Carpiodes carpio	river carpsucker	5	0	5	0.2
Moxostoma erythrurum	golden redhorse	4	0	4	0.2
Etheostoma nigrum	johnny darter	1	2	3	0.1
Morone chrysops	white bass	3	0	3	0.1
Notropis spp.	*Notropis* spp.	1	1	2	0.1
Pylodictis olivaris	flathead catfish	2	0	2	0.1
Labidesthes sicculus	brook silverside	2	0	2	0.1
Lepornis spp.	*Lepomis* spp.	0	2	2	0.1
Lepomis humilis	orangespotted sunfish	0	2	2	0.1
Luxilus cornutus	common shiner	1	0	1	<0.1
Sander vitreus	walleye	1	0	1	<0.1
Esox Lucius	northern pike	1	0	1	<0.1
Ictiobus cyprinellus	bigmouth buffalo	1	0	1	<0.1

Species	Common Name	Individuals Collected [a]			
		Electrofishing	Seine	Combined	Percent (%)
Moxostoma duquesnei	black redhorse	1	0	1	<0.1
Lepomis hybrid	*Lepomis* hybrid	1	0	1	<0.1
	TOTAL	**783**	**1,794**	**2,577**	**100**

[a] Species arranged by number collected.

Source: EA Engineering 2012

3.8 Special Status Species and Habitats

This section addresses species and habitats that are Federally protected under the Endangered Species Act of 1973 (16 U.S.C. § 1531 et seq., herein referred to as ESA) and the Magnuson–Stevens Fishery Conservation and Management Reauthorization Act, as amended (16 U.S.C. §§ 1801–1884, herein referred to as MSA). The ESA, along with the MSA, put requirements on Federal agencies such as the NRC. The terrestrial and aquatic resource sections (Sections 3.6 and 3.7, respectively) discuss other species and habitats protected by other Federal acts and the State of Illinois that do not put requirements on the NRC.

3.8.1 Species and Habitats Protected Under the Endangered Species Act

The FWS and the National Marine Fisheries Service (NMFS) jointly administer the ESA. The FWS manages the protection of, and recovery effort for, listed terrestrial and freshwater species, and NMFS manages the protection of and recovery effort for listed marine and anadromous species. This section describes the action area and considers those species that could occur in the action area under both FWS's and NMFS's jurisdictions.

3.8.1.1 Action Area

The implementing regulations for section 7(a)(2) of the ESA define "action area" as all areas affected directly or indirectly by the Federal action and not merely the immediate area involved in the action (50 CFR 402.02). The action area effectively bounds the analysis of ESA-protected species and habitats because only species that occur within the action area may be affected by the Federal action.

For the purposes of the ESA analysis in this SEIS, the NRC staff considers the action area to be the Byron site (described in Sections 3.1 and 3.6) and the Rock River (described in Section 3.7) from 300 yd (270 m) upstream of the cooling tower blowdown discharge point and extending 0.7 mi (1.1 km) downstream of the discharge point. This area of the river corresponds to the area that EAI and EA Engineering, Science, and Technology determined to be inclusive of effects from Byron operations during preoperational and operational aquatic monitoring (as discussed in Section 3.7). The NRC staff expects all direct and indirect effects of the proposed action to be contained within these areas.

The NRC staff recognizes that while the action area is stationary, Federally listed species can move in and out of the action area. For instance, a migratory fish species could occur in the action area seasonally as it travels up and down the river past Byron. Similarly, a flowering plant known to occur near, but outside, of the action area could appear within the action area over time if its seeds are carried into the action area by wind, water, or animals. Thus, in its analysis, the NRC staff considers not only those species known to occur directly within the action area, but those species that may passively or actively move into the action area. The staff then considers whether the life history of each species makes the species likely to move into the action area where it could be affected by the proposed Byron license renewal.

Within the action area, Federally listed terrestrial species could experience impacts such as habitat disturbance associated with refurbishment or other ground-disturbing activities, cooling tower drift, collisions with cooling towers and transmission lines, exposure to radionuclides, and other direct and indirect impacts associated with station, cooling system, and inscope transmission line operation and maintenance (NRC 2013a). The proposed action has the potential to affect Federally listed aquatic species in several ways: impingement or entrainment of individuals into the cooling system; alteration of the riverine environment through water level reductions, changes in dissolved oxygen, gas supersaturation, eutrophication, and thermal discharges from cooling system operation; habitat loss or alteration from dredging; and exposure to radionuclides (NRC 2013a).

3.8.1.2 Species and Habitats under the FWS's Jurisdiction

Table 3–14 identifies the species under FWS's jurisdiction that occur within Ogle County. Ogle County includes approximately 488,000 ac (198,000 ha) of varying land uses and habitat types. Thus, a Federally listed species that occurs within Ogle County does not necessarily occur within the action area. The NRC staff uses this geographical range as a starting point for its analysis because Federally listed species distribution and critical habitat information is readily available at the county level. Additionally, the action area is a small area of land near the center of and wholly contained within the geographical boundaries of the county. Following the table, descriptions of each species include a determination of whether each species occurs in the action area based on the species' habitat requirements, life history, and available occurrence information.

The NRC compiled the list of species in Table 3–14 from the FWS's Endangered Species Program online database (FWS 2013b); correspondence between the NRC and the FWS (FWS 2013a; NRC 2013b, 2013c); the Illinois Natural Heritage Database (IDNR 2013); information from Exelon's ER (Exelon 2013a); and available scientific studies, surveys, and literature. The NRC staff did not identify any candidate species or proposed or designated critical habitats within the action area.

Table 3–14. Federally Listed Species in Ogle County, Illinois

Species	Common Name	Federal Status [(a)]	Habitat
Mammals			
Myotis septentrionalis	northern long-eared bat	P	Intact forest with relatively full canopy and oaks, maples, beech, or pine present
Myotis sodalis	Indiana bat	E	Hardwood forests and hardwood–pine forests; old-growth forest; agricultural lands and old fields
Plants			
Lespedeza leptostachya	prairie bush clover	T	Dry tallgrass prairie with gravelly soils
Platanthera leucophaea	Eastern prairie fringed orchid	T	Mesic prairie, wetlands, sedge meadows, marsh edges, and bogs with full sun and little to no woody encroachments
Dalea foliosa	leafy prairie clover	E	Mesic and wet-mesic dolomite prairie, limestone cedar glades, and limestone barrens

[(a)] E = endangered; T = threatened; P = proposed for Federal listing

Sources: Exelon 2013a; FWS 2013a, 2013b

<u>Northern Long-Eared Bat *(Myotis septentrionalis)*</u>

The FWS published a proposed rule to list the northern long-eared bat as endangered throughout its range on December 2, 2013 (78 FR 72058). The FWS did not propose to designate critical habitat for the species because it found that such habitat is "not determinable at this time" (78 FR 61046). White-nose syndrome, wind energy development, and loss of habitat specifically linked to surface coal mining in prime summer habitat are factors that have contributed to this species' decline.

The northern long-eared bat is a medium-sized bat that is distinguished from other *Myotis* species by its long ears, which average 0.7 in. (17 mm) in length. This bat inhabits 39 states in the eastern and north central United States and all Canadian provinces west to the southern Yukon Territory and eastern British Columbia. Populations tend to be patchily distributed across its range and are typically composed of small numbers. More than 780 winter hibernacula have been recorded in the United States (36 in Illinois), most of which contain only a few (one to three) individuals. The FWS recognize four United States populations. Northern long-eared bats inhabiting Illinois are considered part of the Midwest population (78 FR 61046).

In the Midwest, the northern long-eared bat is fairly common during summer mist-net surveys and is found infrequently in winter hibernacula surveys (78 FR 61046). The species is regularly caught in consistent numbers in mist-net surveys in the Shawnee National Forest (78 FR 61046), which lies about 320 mi (515 km) south of the Byron site. In summer, bats roost alone or in small colonies under the bark of live or dead trees; in caves or mines; or in manmade structures, such as barns, sheds, and other buildings. The species opportunistically roosts in a variety of trees, including several species of oak, maple, beech, and pine (78 FR 61046). Carter and Feldhamer (2005) found that roosting females in southern Illinois prefer intact forest with greater canopy cover. Northern long-eared bats forage both in flight and on the ground and eat a variety of moths, flies, leafhoppers, caddisflies, and beetles. The species breeds from late July to early October, after which time it will migrate to winter hibernacula. Northern long-eared bats are short-distance migrators and will travel 35 to 55 mi (56 to 89 km) from summer roosts to winter hibernacula (78 FR 61046). Hibernating females store sperm until spring, and give birth to one pup approximately 60 days after fertilization (78 FR 61046). Females raise young in maternity colonies of up to 30 individuals (78 FR 61046).

The majority of the action area is developed or composed of unsuitable habitat types for hibernation, roosting, and foraging. The action area includes some small areas of mixed woodlands, which would likely not be adequately sized to support the northern long-eared bat's preference for intact forests with relatively full canopy cover. The NRC staff did not identify any records or other studies that suggest the occurrence of northern long-eared bats in the action area, and in its ER, Exelon (Exelon 2013a) does not indicate awareness of any records or observations of the northern long-eared bat's occurring on plant property.

Given the available information, the NRC staff concludes that the northern long-eared bat is unlikely to occur within the action area.

<u>Indiana Bat *(Myotis sodalis)*</u>

The FWS listed the Indiana bat as endangered in 1967 (32 FR 4001). The FWS designated critical habitat for the Indiana bat in 1976 (41 FR 41914) to include 11 caves and 2 mines in six states, including a cave in LaSalle County, Illinois. However, no critical habitat for this species occurs in Ogle County.

The Indiana bat is an insectivorous, migratory bat that inhabits the central portion of the Eastern United States and hibernates colonially in caves and mines. The decline of Indiana bats is attributed to urban expansion, habitat loss and degradation, human-caused disturbance of caves or mines, insecticide poisoning, and white-nose syndrome (FWS 2011; Pruitt and TeWinkel 2007).

During summer months, reproductive female bats tend to roost in colonies under slabs of peeling tree bark or cracks within trees in forest fragments, often near agricultural areas (Pruitt and TeWinkel 2007). Colonies may also inhabit closed-canopy, bottomland deciduous forest; riparian habitats; wooded wetlands and floodplains; and upland communities (Pruitt and TeWinkel 2007). Maternity colonies typically consist of 60 to 80 adult females (Whitaker and Brack 2002). Colonies occupy multiple trees for roosting and rearing young (Watrous et al. 2006) and, once established, usually return to the same areas each year (Pruitt and TeWinkel 2007). Nonreproductive females and males do not roost in colonies during the summer; they may remain near the hibernacula or migrate to summer habitat (Pruitt and TeWinkel 2007). High-quality summer habitat includes mature forest stands containing open subcanopies, multiple moderate- to high-quality snags, and trees with exfoliating bark (Farmer et al. 2002). In summer, bats forage for insects along forest edges, riparian areas, and in semiopen forested habitats. In the winter, Indiana bats rely on caves for hibernation. The species prefers hibernacula in areas with karst (limestone, dolomite, and gypsum), although it may also use other cave-like locations, such as mines.

The Indiana Bat Recovery Plan (Pruitt and TeWinkel 2007) indicates that Indiana bats are distributed across 36 of the 102 counties in Illinois. Twenty-two winter hibernacula (16 extant, 4 of uncertain status, and 2 historic) are located throughout these counties. Additionally, 29 extant maternity colonies occur in Illinois, and adult males, nonreproductive females, or both have been captured during summer surveys within 26 of the 36 counties. None of these records identify Ogle County or any of the counties directly neighboring Ogle County as containing hibernacula or maternity colonies. For 2007, the FWS (2009) estimated that Illinois's total population of Indiana bats was 54,095 individuals. According to more recent estimates based on FWS winter surveys conducted in January and February of 2013, the Illinois population of Indiana bats has increased by almost 2,000 over the past 6 years to 55,956 individuals (King 2013).

The majority of the action area is developed or composed of unsuitable habitat types for hibernation, roosting, and foraging. The action area includes approximately 750 ac (300 ha) of land leased for agricultural use as well as some areas of mixed woodlands, meadows, and grasslands that could provide some marginal foraging habitat. The IDNR (2013) Natural Heritage Database indicates that the Indiana bat was last observed in Ogle County in April 2011. However, in March 2012, Exelon generated an IDNR Ecological Compliance Assessment Tool (EcoCAT) report that included Illinois Natural Heritage Database information on species that could potentially be affected by the proposed license renewal. This report did not indicate the presence of the Indiana bat on or in the vicinity of the Byron site (Exelon 2013a). The NRC staff did not identify any other records or other studies that suggest the occurrence of Indiana bats in the action area. Additionally, Exelon (2013a) indicates in its ER that it is not aware of observations or records of Indiana bat occurrences on plant property.

Given the available information, the NRC staff concludes that the Indiana bat is unlikely to occur within the action area.

<u>Prairie Bush Clover *(Lespedeza leptostachya)*</u>

The FWS listed the prairie bush clover as threatened in 1987 (52 FR 781). No critical habitat has been designated for this species.

The prairie bush clover is an herbaceous perennial in the pea family (Fabaceae) that grows up to 1 m (3.2 ft) tall (Smith et al. 1988). The plant has clover-like leaves, pale pink to cream-colored flowers that bloom in mid-July, and silvery-green seed pods (FWS 2013f). Historically, the species spanned 27 counties in Minnesota, Wisconsin, Iowa, and Illinois in the tallgrass prairie region of the Upper Mississippi River Valley. Today, it is present in 24 counties and is most prevalent in northern Iowa and southern Minnesota (Smith et al. 1988). The species inhabits north-facing mesic to dry-mesic prairie slopes in soils with a mixture of loam, colluvium, sand, and gravel and occurs in populations ranging from tens to thousands of individuals (MDNR 2013). The IDNR (2013) Natural Heritage Database indicates that the prairie bush clover was last observed in Ogle County in the summer of 2009.

The March 2012 EcoCAT report indicated that the prairie bush clover may occur in the vicinity of the Byron site (Exelon 2013a). Although the action area includes approximately 150 ac of grasslands (Starke and Cox 2011), these grasslands do not include tallgrass prairie habitat (see Section 3.6 for a description of terrestrial resources). Additionally, Exelon (2012b) states in a biological evaluation submitted to the IDNR that the Byron site does not provide optimal habitat for the prairie bush clover and that it is not aware of observations or records of the species occurring on plant property.

Given the available information, the NRC staff concludes that the prairie bush clover is unlikely to occur within the action area.

Eastern Prairie Fringed Orchid *(Platanthera leucophaea)*

The FWS listed the eastern prairie fringed orchid as threatened in 1989 (54 FR 39857). No critical habitat has been designated for this species.

The eastern prairie fringed orchid is a perennial herb that grows 8 to 40 in. (20 to 102 cm) tall and produces long clusters of up to 40 white flowers in early July (NatureServe 2013). It inhabits mesic prairie, wetlands, sedge meadows, marsh edges, and bogs with full sun and little to no woody encroachments (FWS 2013e). These orchids require hawkmoths for successful pollination, and seedling establishment requires a mycorrhizal relationship with soil fungus (Bowles 1999). Eastern prairie fringed orchids occur in the Eastern United States, Great Lakes states, and in Nova Scotia and Ontario, Canada. Illinois contained the largest historic populations of the species with populations at one time occurring in 33 counties (Bowles 1999). Today, about 20 populations are thought to exist in six counties near the Chicago region (Bowles 1999).

The IDNR (2013) Natural Heritage Database does not indicate that the eastern prairie fringed orchid has been observed in Ogle County, nor did the EcoCAT report indicate that the species occurs on or in the vicinity of the Byron site (Exelon 2013a). Additionally, Exelon (2012b) states in a biological evaluation submitted to the IDNR that the Byron site does not provide optimal habitat for the eastern prairie fringed orchid and that it is not aware of observations or records of the species occurring on plant property.

Given the available information, the NRC staff concludes that the eastern prairie fringed orchid is unlikely to occur within the action area.

Leafy Prairie Clover *(Dalea foliosa)*

The FWS listed the leafy prairie clover as endangered in 1991 (56 FR 19953). No critical habitat has been designated for this species.

The leafy prairie clover is a perennial wildflower in the legume family (Fabaceae) that grows 1 to 2 ft (0.3 to 0.6 m) tall (DeMauro and Bowles 1996). The plant has alternate compound leaves, and small purple-to-pink flowers form in dense spikes at the top of stems in mid-to-late summer. Leafy prairie clovers grow in partial to full sun and thin rocky soils that are moist to slightly dry. The species occurs in northern Illinois, Tennessee, and Alabama. In Illinois, it is found in mesic dolomite prairie remnants along the Des Plains River, while in Tennessee and Alabama, it is found in cedar glades (DeMauro and Bowles 1996; FWS 2013c).

Given that the action area does not include any portion of the Des Plaines River, the leafy prairie clover is unlikely to be present. Additionally, the IDNR (2013) Natural Heritage Database does not indicate that the leafy prairie clover has been observed in Ogle County, and the EcoCAT report did not indicate that the species occurs on or in the vicinity of the Byron site (Exelon 2013a).

Given the available information, the NRC staff concludes that the leafy prairie clover is unlikely to occur within the action area.

3.8.1.3 Species and Habitats Under NMFS's Jurisdiction

As discussed in Section 3.7, the Rock River does not contain marine or anadromous fish species. Therefore, no Federally listed species or habitats under NMFS's jurisdiction occur within the action area.

3.8.2 Species and Habitats Protected Under the Magnuson–Stevens Act

NMFS has not designated essential fish habitat in the Rock River. Therefore, this section does not contain a discussion of any species or habitats protected under the MSA.

3.9 Historic and Cultural Resources

This section discusses the cultural background and the known historic and cultural resources found on and in the vicinity of Byron. The discussion is based on a review of historic and cultural resource surveys and other background information on the region surrounding Byron. In addition, a records search was performed via the Illinois Historic Preservation Agency (IHPA) (Pauketat 1993) to obtain the most updated information about historic and cultural resources in the region.

The Area of Potential Effect (APE) is the area at the Byron power plant site, the transmission lines up to the first substation, and immediate environs that may be affected by the license renewal decision and land-disturbing activities associated with continued reactor operations. For this analysis, the first substation (345-kV Byron switchyard) is located on the Byron site (Exelon 2013b). The APE may extend beyond the immediate environs in instances where land-disturbing maintenance and operations activities during the license renewal term or refurbishment activities could potentially have an effect. See Figure 3–3.

3.9.1 Cultural Background

Human occupation in the vicinity of Byron site is generally characterized according to the following chronological sequence (Pauketat 1993):

- Paleo-Indian Period (12,000 – 10,000 before present (BP)),
- Archaic Period (10,000 – 3,000 BP),
- Woodland Period (3,000 – 1,100 BP),
- Mississippian Period (1,100 – 400 BP (ca. A.D. 900 – 1600)), and
- Protohistoric/Historic Period (400 – Present (ca. A.D. 1600 – Present)).

<u>Paleo-Indian Period (12,000 – 10,000 BP)</u>

The earliest evidence of people living in Illinois dates to the Paleo-Indian Period. Paleo-Indian sites are generally found upland or on river terraces and are characterized by specific types of projectile points (i.e., fluted Clovis and Folsom points) and stone tools such as gravers, scrapers, or large blades. These artifacts often occur in association with mastodon remains, suggesting a reliance on megafauna (e.g., mammoth, ground sloth, and saber-tooth tiger) for subsistence, along with plants, small game, birds, and amphibians. Social organization consisted of small, highly nomadic bands of hunter-gatherers, leaving Paleo-Indian sites with little detailed archaeological information (Neusius and Gross 2007; Pauketat 1993).

<u>Archaic Period (10,000 – 3,000 BP)</u>

The Archaic Period was a time of major climatic shifts as colder environments transitioned to warmer environments similar to modern conditions. In response to this shift, new technologies and subsistence strategies were developed during this time. The Archaic Period is often divided into early, middle, and late subperiods. The Early Archaic Period is characterized by a shift from nomadic to sedentary settlement patterns, with central base camps located on river terraces and smaller hunting camps located in upland areas. This subperiod also shows an increased reliance on wild plant foods, small game, and aquatic resources. The Middle Archaic

Period is characterized by an increased number of settlement sites on high stream terraces, which may reflect population increases. While subsistence and settlement patterns remained fairly similar to the Early Archaic Period, artifact assemblages suggest increased exploitation of aquatic resources as well as new artifacts such as pecked and ground stone tools used for intensive processing of nuts, banner stones that signaled the innovation of a new projectile technology called the atlatl or spear-thrower, and grooved axes. The Late Archaic Period is characterized by an increase in the number and size of settlement sites, which indicates an increase in population and a more sedentary lifestyle. New features of Late Archaic artifact assemblages, such as crude ceramic vessels, represent a shift toward increased reliance on horticulture as a subsistence strategy, although hunting and gathering would have continued (Fagan 2005; Neusius and Gross 2007; Pauketat 1993).

<u>Woodland Period (3,000 – 1,100 BP)</u>

The Woodland Period is also often divided into early, middle and late periods. However, the distinction between the early and middle period is not fixed. The Woodland Period is marked by an increase in more permanent settlements, changes in burial practices, increased cultivation of plants such as sunflowers and cucurbits (i.e., squashes, gourds, melons, etc.), and a rise in the manufacture and use of pottery (Fagan 2005). During the Middle Woodland Period, the large and complex Hopewell Culture emerged in the northeastern and midwestern United States, including Illinois. This culture is characterized by settlement in villages, increased reliance on intensive horticulture, burial mounds, and long-distance trade networks. These long-distance networks allowed the trade of exotic materials, such as marine shells from the Gulf Coast, obsidian from the Rocky Mountains, copper from Lake Superior, and mica from the Appalachian Mountains far outside their immediate locations. Evidence of the Illinois Hopewell culture is found primarily in the bluffs and floodplains of the Illinois River Valley. The burial mounds of this period often included central features, lined with logs, and filled with grave goods. Different burial treatments within the mounds point to social stratification within society, but through sex and age rather than hereditary lineage (Neusius and Gross 2007). The Late Woodland Period is characterized by an increase in settlement sites, which suggests a rise in population and/or a change in settlement patterns from large, centralized village sites to smaller, dispersed habitation sites. Late Woodland Period artifact assemblages are characterized by an increase in thin-walled plain ceramic types and stemmed and side-notched projectile points. The sudden appearance of very small, thin triangular projectile points between 1,300 and 1,400 BP indicates the invention of bow-and-arrow technology and suggests a corresponding change in hunting techniques (Fagan 2005).

<u>Mississippian Period (1,100 – 400 BP (ca. A.D. 900 – 1600))</u>

The Mississippian Period is characterized by major changes in settlement, subsistence patterns, and social structure. Large highly centralized chiefdoms with permanent settlement sites supported by numerous satellite villages emerged during this period. The platform mound, a new ceremonial earthen mound appeared in association with these permanent settlements. Platform mounds, burial mounds, and defensive structures, such as moats and palisades, were often constructed in clusters in settlements of this period and were common in the larger river valleys of the Midwest. Mississippian Period subsistence relied heavily on maize agriculture, as well as hunting and gathering. Long-distance trading increased and craft specialists produced highly specialized lithic and ceramic artifacts, beadwork and shell pendants (Fagan 2005).

In southern Wisconsin and northern Illinois, the emerging Mississippian culture was blended with the receding Woodland culture to produce the Oneota tradition. The Oneota were organized in permanent villages, produced unique ceramic artifacts, and relied on a mixed subsistence strategy of hunting and gathering, though cultivation of maize was practiced. Burial traditions varied from the mounds of the Woodland Period to nonmounded cemeteries near their villages (Exelon 2013a; Neusius and Gross 2007).

Protohistoric/Historic Period (A.D. 1600 – Present)

The end of the Mississippian Period is characterized by severe social, political, and demographic changes that resulted from indirect and direct contact with Europeans. In particular, it is believed that the introduction of European infectious diseases such as smallpox, yellow fever, typhoid, and influenza severely decimated Native American populations, which had no immunity to these diseases. The spread of these diseases, which were fatal to large numbers of Native Americans, resulted in the widespread abandonment of villages and a concurrent collapse of Native American socioeconomic networks, such that by the time of widespread European contact and settlement, the Mississippian chiefdoms were gone (Fagan 2005). During this time period, Illinois was primarily populated with a confederation of tribes known as the Illinois, or Illiniwek, and the Miami tribe. During the 1700s and early 1800s, new tribes migrated to Illinois, including the Iroquois, Fox (Mesquakie), Ioway, Kickapoo, Mascouten, Piankashaw, Potawatomi, Sauk, Shawnee, Wea, and Winnebago. Competition for resources led to sporadic war among the Illinois and surrounding tribes for approximately the next 120 years (ISM 2002). French explorers and fur traders travelled down the Mississippi River into Illinois in the 17th century. Early European settlements were established along the river systems by settlers seeking to profit from the fur trade. Illinois became part of the United States Northwest Territory at the close of the American Revolution and became a state in 1818 with Ogle County being formed in 1836. The area surrounding the Byron site has principally been used as agricultural land from this period onward (Ogle County 2014).

3.9.2 Historic and Cultural Resources

Historic and cultural resources include prehistoric era and historic era archaeological sites, historic districts, and buildings, as well as any site, structure, or object that may be considered eligible for listing on the National Register of Historic Places (NRHP). Historic and cultural resources also include traditional cultural properties that are important to a living community of people for maintaining their culture. "Historic property" is the legal term for a historic and/or cultural resource that is eligible for listing on the NRHP.

A review of databases maintained by the National Park Service (NPS) indicates that there are 24 properties listed in the NRHP within Ogle County, including one that has been designated a National Historic Landmark (NHL) (NPS 2014a, 2014b). These historic properties reflect the historic cultural contexts for the Byron property and include historic buildings, structures, and districts dating from the mid-18th through mid-20th centuries. However, none of the 24 historic properties are located within the boundaries of the Byron property. The closest NRHP-eligible site is in Byron, Illinois, approximately 4 mi (6 km) to the northeast.

In 1973 and 1974, Phase I and Phase II archaeological surveys were undertaken by the University of Wisconsin – Milwaukee for all lands purchased by ComEd for the proposed construction of Byron. These surveys identified eight archaeological sites and recommended fencing sites along the Rock River for protection if any construction would occur in their immediate area. Surveyors also recommended leaving a 15-meter (m) (50-ft) buffer between the other identified sites and any new construction (Birmingham and Fowler 1974). The Illinois State Historic Preservation Officer (SHPO) concurred that operation of Byron would not result in any significant impact on historic and cultural sites in the area (Exelon 2013b).

A search of the Illinois State Archaeological Site Files, a database maintained by the Illinois SHPO, by NRC staff identified four cultural resources within the current confines of the Byron site, with one site immediately adjacent to the property boundary. All sites are ineligible for the NRHP. These sites are identified in Table 3–15.

Table 3–15. Cultural Resources Within the Byron Site

Site	On the Byron Site	Description	NRHP
11OG153	No	Archaic dwelling and/or hearth	Ineligible
11OG155	Yes	Prehistoric; scattered surface finds of projectile points, scrapers, and flakes	Ineligible
11OG156	Yes	Prehistoric; scattered surface finds of projectile points, scrapers, and flakes	Ineligible
11OG157	Yes	Prehistoric; scattered surface finds of projectile points, scrapers, and flakes	Ineligible
11OG158	Yes	Prehistoric; scattered surface finds of projectile points, scrapers, and flakes	Ineligible

Source: Illinois Inventory of Archaeological Sites, ISM 2014

3.10 Socioeconomics

This section describes current socioeconomic factors that have the potential to be directly or indirectly affected by changes in operations at Byron. Byron, and the communities that support it, can be described as a dynamic socioeconomic system. The communities supply the people, goods, and services required to operate the nuclear power plant. Power plant operations, in turn, supply wages and benefits for people and dollar expenditures for goods and services. The measure of a community’s ability to support Byron operations depends on its ability to respond to changing environmental, social, economic, and demographic conditions.

3.10.1 Power Plant Employment and Expenditures

The socioeconomics region of influence (ROI) is defined by the areas where Byron employees and their families reside, spend their income, and use their benefits, thus affecting the economic conditions of the region. Exelon Generation employs a permanent workforce of approximately 870 employees and 20 long-term contract employees (Exelon 2013a). Approximately 82 percent of Byron employees reside in a three-county area in northern Illinois in Lee, Ogle, and Winnebago Counties. Most of the remaining 18 percent of the workforce are spread among 18 other counties in Illinois and 5 counties outside of Illinois, with numbers ranging from 1 to 53 employees per county (Exelon 2013a). Given the residential locations of Byron employees, the most significant effects of plant operations are likely to occur in Ogle, Lee, and Winnebago counties. Table 3–16 summarizes the Byron workforce geographic distribution. The focus of the socioeconomic impact analysis in this SEIS is, therefore, on the impacts of continued Byron operations on these three counties, also termed the ROI.

Table 3–16. Exelon Generation Employees Residence by County

County	Number of Employees	Percentage of Total
DeKalb	25	3
Lee	115	13
Ogle	352	41
Whiteside	52	6
Winnebago	243	28
Other counties	80	9
Total	**867**	**100**

Source: Exelon 2013b

Exelon purchases goods and services to facilitate Byron operations. While specialized equipment and services are procured from a wider region, some proportion of the goods and services used in plant operations are acquired from within the ROI. These transactions fuel a portion of the local economy, as jobs are provided and additional local purchases are made by plant suppliers.

The Byron units are on staggered 18-month refueling intervals. During refueling outages, site employment typically increases by an average of 1,400 temporary workers for approximately 20 days (Exelon 2013a). Outage workers are drawn from all regions of the country; however, the majority would be expected to come from Illinois, Wisconsin, and other Midwestern States.

3.10.2 Regional Economic Characteristics

This section presents information on employment and income in the Byron socioeconomic ROI. The three-county ROI is predominantly rural and agricultural. Agricultural and forested land comprises the majority of the land use in Ogle, Lee, and Winnebago Counties. Urban developed land makes up only about 8, 7, and 25 percent of total land area of each county, respectively (NASS 2012b).

3.10.2.1 Employment and Income

From 2000 to 2012, the labor force in the Byron ROI decreased approximately 4 percent to just over 183,000. The number of employed persons declined by about 10.6 percent over the same period, to approximately 163,000. Consequently, the number of unemployed people in the ROI has increased nearly 135 percent in the same period, to over 11,700, or about 6.7 percent of the current workforce—up from 4.5 percent in 2000 (BLS 2014).

According to the U.S. Census Bureau's (USCB's) 2008–2012 American Community Survey 5-Year Estimates, the educational, health, and social services industry represented the largest employment sector in the socioeconomic ROI (22.5 percent) followed by manufacturing (21 percent) and retail (11.4 percent). A list of employment by industry in each county of the ROI is provided in Table 3–17.

Table 3–17. Employment by Industry in the Byron ROI (5-year estimates 2008–2012)

Industry	Lee	Ogle	Winnebago	Total	Percent
Total employed civilian workers	16,202	25,827	131,758	173,787	–
Agriculture, forestry, fishing, hunting, and mining	463	606	648	1,717	1.0
Construction	851	1,834	6,525	9,210	5.3
Manufacturing	3,127	4,360	28,961	36,448	21.0
Wholesale trade	564	875	3,104	4,543	2.6
Retail trade	1,731	3,087	14,929	19,747	11.4
Transportation, warehousing, and utilities	1,074	2,420	7,585	11,079	6.4
Information	220	503	2,243	2,966	1.7
Finance, insurance, real estate, rental, and leasing	644	1,237	6,466	8,347	4.8
Professional, scientific, management, administrative, and waste management services	988	1,924	10,314	13,226	7.6
Educational, health, and social services	3,975	5,014	30,097	39,086	22.5
Arts, entertainment, recreation, accommodation, and food services	1,143	1,709	10,169	13,021	7.5
Other services (except public administration)	632	1,342	6,938	8,912	5.1
Public administration	790	916	3,779	5,485	3.2

Source: USCB 2014a

Major employers in Ogle County, the county in which Byron is located, are listed in Table 3–18. Exelon Generation is shown as the largest employer in the county.

Estimated income information for the Byron ROI is presented in Table 3–19. According to the USCB's 2008–2012 American Community Survey 5-Year Estimates, people living in the three-county ROI had median household and per capita incomes below the State average. Winnebago County has the highest percentages of persons (17 percent) living below the official poverty level when compared to the other two counties and the State of Illinois as a whole. Lee and Ogle Counties had 10 percent, respectively, and the State of Illinois as a whole had 13.7 percent. The percentage of families living below the poverty level in Lee and Ogle Counties (7.4 percent, respectively) was lower than the percentage of families in Winnebago County and the State of Illinois as a whole (12.8 percent and 10 percent, respectively) (USCB 2014a).

Table 3–18. Major Employers in Ogle County in 2012

Employer (City or Village)	Industry/Product/Service	Number of Employees
Exelon Generation (Byron)	Electric utility, nuclear power generation	870
Rochelle Foods/Hormel (Rochelle)	Pork products	760
E.D. Etnyre & Co. (Oregon)	Road construction equipment manufacturing	350
Pine Crest Manor (Mt. Morris)	Nursing care facility	312
Rochelle Schools (Rochelle)	Education	305
Rochelle Hospital (Rochelle)	Health care	265
Veolia (Davis Junction)	Solid waste disposal/landfill operation	251
Byron Schools (Byron)	Education	250
Sara Lee (Rochelle)	Cold storage, sales & marketing	235
Americold (Rochelle)	Frozen foods storage & distribution	232
Quality Metal Finishing, Inc. (Byron)	Metal plating/finishing	210
Woods Equipment Co. (Oregon)	Manufacturing of attachments and replacement parts for agricultural, landscape and light construction markets	200
PNC, Inc. (Polo)	Manufacturer of custom electromagnet solenoid coils and wiring harnesses for the automotive and hydraulic industry	200
Silgan Containers (Rochelle)	Provider of metal food packaging products	200
Village of Progress (Oregon)	Social service organization	169
Austin-Westran (Byron)	Metal cabinets/metal fabrication	155
County of Ogle (Oregon)	County government	150
Bay Valley Foods (Rochelle)	Labeling, warehousing, distribution of shelf-stable foods	150
Del Monte, Inc. (Rochelle)	Warehousing and distribution of canned food products	150
Ryder Logistics (Rochelle)	Warehousing and distribution of refrigerated/frozen food products	135
City of Rochelle (Rochelle)	Municipal government	125
The Neighbors (Byron)	Nursing care facility	115
Rochelle Nursing Home (Rochelle)	Nursing care facility	115

Source: Ogle County 2012

Table 3–19. Estimated Income Information for the Byron ROI (5-year estimates 2008–2012)

	Lee	Ogle	Winnebago	Illinois
Median household income (dollars)[(a)]	50,342	55,590	47,573	56,853
Per capita income (dollars)[(a)]	25,484	26,331	24,404	29,519
Individuals living below the poverty level (percent)	10.0	10.0	17.0	13.7
Families living below the poverty level (percent)	7.4	7.4	12.8	10.0

[(a)] In 2012 inflation adjusted dollars

Source: USCB 2014a

3.10.2.2 Unemployment

According to the USCB's 2008–2012 American Community Survey 5-Year Estimates, the unemployment rates were: Lee County, 9.2 percent; Ogle County, 9.8 percent; and Winnebago County, 12 percent. Comparatively, the State of Illinois's unemployment rate during this same time period was 9.9 percent (USCB 2014a).

3.10.3 Demographic Characteristics

According to the 2010 Census, an estimated 248,387 people lived within 20 mi (32 km) of Byron, which equates to a population density of 198 persons per mi^2 (Exelon 2013a). This translates to a Category 4, "least sparse" population density using the generic environmental impact statement (GEIS) measure of sparseness (greater than or equal to 120 persons per mi^2 within 20 mi). An estimated 1,247,087 people live within 50 mi (80 km) of Byron with a population density of 159 persons per mi^2 (Exelon 2013a). This translates to a Category 3 density, using the GEIS measure of proximity (one or more cities with 100,000 or more persons and less than 190 persons per mi^2 within 50 mi (80 km)). The nearest city with a population greater than 100,000 is Rockford, Illinois (17 mi (27 km) northeast), with a 2010 population of 152,871 (USCB 2014b). Therefore, Byron is located in a high population area based on the GEIS sparseness and proximity matrix.

Table 3–20 shows population projections and percent growth from 1970 to 2060 in the three-county Byron ROI. The population in the ROI has increased over the previous 2 decades (2000 and 2010). Based on State forecasts, the population is expected to continue to increase at a moderate to high rate due in part to the close proximity of the ROI to Chicago. Population projections for years 2020 and 2030 shown in the table were developed by the Illinois Department of Commerce and Economic Opportunity (DCEO) and are based on projected 2000 population census estimates (see Table 3–21). As a result, the projected 2020 and 2030 population estimates may be overstated, as actual population data from the 2000 and 2010 decennial census were lower than the 2000 and 2010 population estimates projected by the DCEO.

Table 3–20. Population and Percent Growth in Byron ROI Counties 1970–2010, 2012 (estimated), and Projected for 2020–2060

Year	Lee County		Ogle County		Winnebago County	
	Population	Percent growth	Population	Percent growth	Population	Percent growth
1970	37,947	–	42,876	–	246,623	–
1980	36,328	−4.3	46,338	8.1	250,884	1.7
1990	34,392	−5.3	45,957	−0.8	252,913	0.8
2000	36,062	4.9	51,032	11.0	278,418	10.1
2010	36,031	−0.1	53,497	4.8	295,266	6.1
2012*	**35,037**	**−2.8**	**52,848**	**−1.2**	**292,069**	**−1.1**
2020	37,939	3.8	59,230	8.3	337,049	9.7
2030	38,923	2.6	63,765	7.7	359,900	6.8
2040	38,971	0.1	66,245	3.9	377,172	4.8
2050	39,645	1.7	69,943	5.6	400,439	6.2
2060	40,319	1.7	73,640	5.3	423,705	5.8

Sources: Decennial population data for 1970–2010, and estimated 2012 (USCB 2014b); projections for 2020–2030 by Illinois Department of Commerce and Economic Opportunity (DCEO 2012); 2040–2060 calculated

* Bold indicates most recent population estimate from the U.S. Census.

Table 3–21. Illinois Department of Commerce and Economic Opportunity (DCEO) Population Projections for 2000–2030

Year	Lee County		Ogle County		Winnebago County	
	Population	Percent growth	Population	Percent growth	Population	Percent growth
2000	36,118	–	51,119	–	278,902	–
2010	36,554	1.2	54,704	7.0	307,349	10.2
2020	37,939	3.8	59,230	8.3	337,049	9.7
2030	38,923	2.6	63,765	7.7	359,900	6.8

Source: DCEO 2012

The 2010 Census demographic profile of the three-county region of influence population is presented in Table 3–22. According to the 2010 Census, minorities (race and ethnicity combined) comprised 23.7 percent of the total three-county population. The largest minority populations in the three-county ROI are Hispanic or Latino (10.1 percent) and Black or African-American (9.8 percent).

Table 3–22. Demographic Profile of the Population in the Byron ROI in 2010

	Lee	Ogle	Winnebago	ROI
Total Population	36,031	53,497	295,266	384,794
Race (percent of total population, Not-Hispanic or Latino)				
White	88.3	88.6	72.5	76.3
Black or African-American	4.7	0.9	12.0	9.8
American Indian & Alaska Native	0.1	0.2	0.2	0.2
Asian	0.7	0.5	2.3	1.9
Native Hawaiian & Other Pacific Islander	0.0	0.0	0.0	0.0
Some other race	0.1	0.0	0.1	0.1
Two or more races	1.0	0.9	2.0	1.8
Ethnicity				
Hispanic or Latino	1,802	4,741	32,177	38,720
Percent of total population	5.0	8.9	10.9	10.1
Minority population (including Hispanic or Latino ethnicity)				
Total minority population	4,207	6,072	81,070	91,349
Percent minority	11.7	11.4	27.5	23.7

Source: USCB 2014c

3.10.3.1 Transient Population

Within 50 mi (80 km) of Byron, colleges and recreational opportunities attract daily and seasonal visitors who create a demand for temporary housing and services. In 2013, approximately 27,700 students attended colleges and universities within 50 mi (80 km) of Byron (NCES 2013).

Based on the 2008–2012 American Community Survey (ACS) estimates, approximately 18,800 seasonal housing units are located within 50 mi (80 km) of Byron. Of those, 1,168 were located in the Byron ROI. Table 3–23 presents information about seasonal housing for the counties located all or partly within 50 mi (80 km) of Byron.

Table 3–23. 2007–2011 Estimated Seasonal Housing in Counties Located Within 50 mi (80 km) of Byron

County [(a)]	Total Seasonal Housing Units	Vacant Housing Units: for Seasonal, Recreational, or Occasional Use	Percent
Illinois			
Boone	19,909	38	0.2
Bureau	15,712	219	1.4
Carroll	8,432	819	9.7
DeKalb	40,932	305	0.7
Henry	22,135	118	0.5
Jo Daviess	13,560	2,797	20.6
Kane	181,587	399	0.2
Kendall	40,002	82	0.2
La Salle	49,924	731	1.5
Lee	***15,049***	***373***	***2.5***
McHenry	116,015	1,136	1.0
Ogle	***22,539***	***321***	***1.4***
Stephenson	22,076	427	1.9
Whiteside	25,742	233	0.9
Winnebago	***125,928***	***474***	***0.4***
County Subtotal	**719,542**	**8,472**	**1.2**
Iowa			
Clinton	21,753	172	0.8
Jackson	9,400	465	4.9
County Subtotal	**31,153**	**637**	**2.0**
Wisconsin			
Green	15,857	316	2.0
Lafayette	7,218	140	1.9
Rock	68,369	1,105	1.6
Walworth	51,441	8,146	15.8
County Subtotal	**142,885**	**9,707**	**6.8**
Total	**893,580**	**18,816**	**2.1**

[(a)] Counties within a 50 mi (80 km) radius of Byron

Source: USCB 2014d

3.10.3.2 Migrant Farm Workers

Migrant farm workers are individuals whose employment requires travel to harvest agricultural crops. These workers may or may not have a permanent residence. Some migrant workers follow the harvesting of crops, particularly fruit, throughout rural areas of the United States. Others may be permanent residents near Byron and travel from farm to farm harvesting crops.

Migrant workers may be members of minority or low-income populations. Because they travel and can spend a significant amount of time in an area without being actual residents, migrant workers may be unavailable for counting by census takers. If uncounted, these workers would be "underrepresented" in USCB minority and low-income population counts.

Information about migrant farm and temporary labor was collected in the 2007 Census of Agriculture. Table 3–24 supplies information about migrant farm workers and temporary farm labor (less than 150 days) within 50 mi (80 km) of Byron. According to the 2007 Census of Agriculture, approximately 14,100 farm workers were hired to work for less than 150 days and were employed on 4,689 farms within 50 mi (80 km) of Byron. The county with the highest number of temporary farm workers (1,127) on 219 farms was McHenry County, Illinois (NASS 2012a).

In the 2002 Census of Agriculture, farm operators were asked for the first time whether or not they hired migrant workers—defined as a farm worker whose employment required travel—to do work that prevented the migrant workers from returning to their permanent place of residence the same day. A total of 182 farms, in the 50-mi radius of Byron, reported hiring migrant workers in the 2007 Census of Agriculture. DeKalb County, Illinois, reported the most farms with migrant farm labor (16 farms) (NASS 2012a).

Table 3–24. Migrant Farm Workers and Temporary Farm Labor in Counties Located within 50 mi (80 km) of Byron

County[(a)]	Number of Farms with Hired Farm Labor[(b)]	Number of Farms Hiring Workers for Less Than 150 Days[(b)]	Number of Farm Workers Working for Less Than 150 Days[(b)]	Number of Farms Reporting Migrant Farm Labor[(b)]
Illinois				
Boone	121	97	274	12
Bureau	321	278	786	4
Carroll	202	165	382	9
DeKalb	269	223	1,014	16
Henry	423	344	808	15
Jo Daviess	214	163	449	4
Kane	231	172	798	13
Kendall	111	94	371	11
La Salle	402	338	760	9
Lee[(c)]	***242***	***203***	***462***	***10***
McHenry	284	219	1,127	15
Ogle[(c)]	***293***	***258***	***629***	***7***
Stephenson	286	209	560	11
Whiteside	316	273	739	9
Winnebago[(c)]	***146***	***125***	***364***	***1***
County Subtotal	**3,861**	**3,161**	**9,523**	**146**
Iowa				
Clinton	411	341	1,021	1
Jackson	234	190	489	2
County Subtotal	**645**	**531**	**1,510**	**3**
Wisconsin				
Green	403	284	662	6
Lafayette	377	267	718	13
Rock	348	266	933	8
Walworth	252	180	747	6
County Subtotal	**1,380**	**997**	**3,060**	**33**
Total	**5,886**	**4,689**	**14,093**	**182**

County [a]	Number of Farms with Hired Farm Labor [b]	Number of Farms Hiring Workers for Less Than 150 Days [b]	Number of Farm Workers Working for Less Than 150 Days [b]	Number of Farms Reporting Migrant Farm Labor [b]

[a] Counties within 50 mi (80 km) of Byron with at least one block group located within the 50-mi radius
[b] Table 7. Hired farm Labor—Workers and Payroll: 2007
[c] Counties in the socioeconomic ROI

Source: 2007 Census of Agriculture — County Data (NASS 2012a)

3.10.4 Housing and Community Services

This section presents information regarding housing and local public services, including education and water supply.

3.10.4.1 Housing

Table 3–25 lists the total number of occupied and vacant housing units, vacancy rates, and median value in the ROI. Based on the USCB's 2008–2012 ACS 5-Year Estimates, there were nearly 164,000 housing units in the socioeconomic region, of which nearly 148,000 were occupied. The median values of owner-occupied housing units in the ROI range from $113,000 in Lee County to about $151,000 in Ogle County. The vacancy rate also varied considerably between the three counties, from 8 percent in Ogle County to 10.2 percent in Winnebago County (USCB 2014e).

Table 3–25. Housing in the Byron ROI (2008−2012, 5-year estimate)

	Lee County	Ogle County	Winnebago County	ROI
Total housing units	15,049	22,539	125,928	163,516
Occupied housing units	13,686	20,728	113,119	147,533
Total vacant housing units	1,363	1,811	12,809	15,983
Percent total vacant	9.1	8.0	10.2	9.8
Owner occupied units	10,195	15,496	76,421	102,112
Median value (dollars)	113,000	151,400	127,500	129,679
Owner vacancy rate (percent)	1.3	1.8	1.2	1.3
Renter occupied units	3,491	5,232	36,698	45,421
Median rent (dollars/month)	622	669	721	707
Rental vacancy rate (percent)	5.4	7.1	5.2	5.4

Source: USCB 2014e

3.10.4.2 Education

There are six public school districts in Lee County with 15 schools and an average daily total enrollment of approximately 4,600 students during the 2010–2011 school year. Winnebago County has 11 public school districts with 95 schools and had approximately 38,600 students. In Ogle County, the county in which Byron is located, there are 10 public school districts with 27 schools and over 9,600 students (ISBE 2014).

3.10.4.3 Public Water Supply

Table 2.9-1 of Exelon's ER (Exelon 2013a) lists the largest public water suppliers in Ogle, Lee, and Winnebago Counties and provides water use and supply information for those suppliers. The discussion of public water supply systems is limited to major municipal water systems in the local area. Most of the water for domestic, municipal, and industrial use in the region comes from groundwater. Information about municipal water suppliers close to Byron, their maximum design yields, reported annual average usage, and population served are presented in Table 3–26. All major public water suppliers in Ogle, Lee, and Winnebago Counties obtain their supplies from groundwater. Currently, there is excess capacity in every major public water system in the three counties. Byron gets potable water from two onsite groundwater wells not connected to a public water system.

Table 3–26. Local Public Water Supply Systems (in million gallons per day (mgd))

Public Water System	County	Usage (mgd)	Pump Capacity (mgd)	Population Served [a]
Dixon	Lee	2.2	12.0	16,100
Woodhaven	Lee	0.4	2.1	4,100
Byron	Ogle	0.6	2.3	4,101
Oregon	Ogle	0.4	3.1	4,101
Rochelle	Ogle	2.7	7.2	9,850
Cherry Valley	Winnebago	0.6	6.2	5,000
Illinois American – South Beloit	Winnebago	0.7	NA	6,750
Loves Park	Winnebago	3.0	6.9	22,476
North Park Public Water District	Winnebago	3.5	18.1	35,737
Rockford	Winnebago	25.6	125.0	155,000
Rockton	Winnebago	0.8	6.2	7,440

NA = Not available

[a] Safe Drinking Water Search for the State of Illinois (EPA 2014b)

Sources: EPA 2014b; Exelon 2013a

3.10.5 Tax Revenues

Property taxes paid by Exelon Generation for Byron are generally determined using the equalized assessed value (EAV) set by the county assessor, and the tax levy and rates set by each taxing district. Periodically, Exelon Generation enters into negotiations (which may result in a “settlement agreement”) with Ogle County and the other taxing districts to set the EAV for Byron. Negotiations can consider, but are not limited to, property valuation approaches, tax “triggers” (or limits), and payments in addition to taxes (PIAT). Exelon’s last settlement agreement for Byron was signed on November 8, 2008, and covered tax years 2005 through 2011, which included negotiated triggers or tax limits. If tax levies exceeded these negotiated triggers, Exelon Generation could reduce Byron’s property tax obligation by the amounts in excess of the triggers. Exelon Generation also agreed to make additional payments (PIAT) to specific tax recipients. These payments are not considered tax payments in the traditional sense. They have fewer limitations for use and provide additional benefits for recipients. In accordance with the 2008 settlement agreement, Exelon Generation made two PIAT payments of $2,302,000 each; one in 2008 and the other in 2010 (Exelon 2013b). Table 3–27 lists the PIAT payments and their recipients.

Exelon Generation and the taxing bodies have not entered into another settlement agreement, although negotiations have begun. Negotiations are in the early stages, and PIAT payments may be included as part of any future settlement agreement. Exelon Generation expects the recipients would remain the same as those listed in Table 3–27 because those are the taxing institutions that levy tax on the two power block Property Index Numbers (PINs). The settlement agreements have historically only settled the EAV for the two power block PINs (Exelon 2013b).

Table 3–27. PIAT Payments and Recipients, 2008 and 2010

Tax Recipients	Dollars	Percent of Total
Ogle County	270,863	11.8
Byron Fire Protection District	166,564	7.2
Byron Library District	56,659	2.5
Byron Museum District	6,256	0.3
Byron Forest Preserve District	127,339	5.5
Oregon Park District	147,137	6.4
Rockvale Township	12,888	0.6
Rockvale Township Road District	30,192	1.3
Rock Valley College	90,874	3.9
Byron Community Unit School District No. 226	1,346,079	58.5
Kishwaukee College	4,926	0.2
Oregon Community Unit School District No. 220	42,223	1.8
Total	**2,302,000**	**100.0**

Source: Exelon 2013a

The Ogle County Assessor set the EAV for the 2012 tax year at $499 million, which is more than 4 percent higher than the EAV set under the existing settlement agreement. Exelon Generation believes the higher EAV overvalues Byron because an independent appraiser set the 2012 value of the station at $1.85 billion, which equates to an EAV of approximately $296.9 million. On this basis, Exelon Generation appealed the 2012 assessment to the Ogle County Board of Review. Upon an unfavorable ruling by the Board of Review, Exelon Generation then appealed the assessment to the Illinois Property Tax Appeal Board. The company will continue to negotiate with the taxing bodies to reach a settlement agreement, and in its absence, will appeal any assessment that does not reflect a valuation of the plant that they believe is fair (Exelon 2013b).

Pending the outcome of such actions, Exelon Generation has paid the tax assessed for 2012 (an increase of more than $2 million over the prior year, see Table 3–28). This increase was based on the EAV set by the assessor for the two combined power block PINs. Exelon Generation actually pays property taxes on 48 land parcels or PINs at Byron. The total taxes paid by Exelon Generation include taxes for all of the PINs (Exelon 2013b).

As previously discussed, the Ogle County Treasurer collects the property tax payment and disperses it to various institutions within the county to partially fund their operating budgets. These include, but are not limited to, the Byron Forest Preserve, the Oregon Park District, the Rock Valley Community College 511, the Byron Unit 226 School District, the Byron Fire District, the Byron Library District, Ogle County, and Rockvale Township (Exelon 2013a). From 2008 through 2012, Ogle County's total adjusted property tax levies ranged from approximately $111.3 to $116.6 million annually (see Table 3–28). From 2008 through 2012, Byron's total property tax payments (after tax triggers and not including PIAT payments) represented 26.0 to 28.3 percent of Ogle County's total adjusted property tax levy (see Table 3–28).

Table 3–28. Property Tax Payment Comparison, All Taxing Districts Combined

Year	Total Combined Taxing District Levy—Ogle County (after adjustments) (millions of dollars)	Byron Property Tax Payment (after tax triggers have been applied and not including PIAT payments) (millions of dollars)	Byron Payment as Percent of Total District Levy (percent)
2008	111.3	29.1	26.1
2009	113.8	29.6	26.0
2010	114.5	30.2	26.4
2011	113.9	30.8	27.0
2012	[a] 116.6	[a] 33.0	[a] 28.3

[a] Preliminary data

Sources: Exelon 2013a, 2013b

The recipient of the largest percentage of Byron's property tax payment is the Byron Unit 226 School District (Exelon 2013a). Table 3–29 compares Byron's property tax payments (after tax triggers and not including PIAT payments) to the Byron Unit 226 School District's adjusted total property tax levies. From 2008 through 2012, Byron's property tax payments to the school district represented 72.9 to 75.6 percent of the school district's total adjusted property tax levies (see Table 3–29).

Table 3–29. Property Tax Payment Comparison, All Taxing Districts Combined

Year	Total Byron Unit 226 School District Levy (after adjustments) (millions of dollars)	Byron Unit 226 School District Portion of Byron Property Tax Payment (after tax triggers have been applied and not including PIAT payments) (millions of dollars)	Byron Payment as Percent of Total District Levy (percent)
2008	22.4	16.3	72.9
2009	22.7	16.7	73.3
2010	23.1	17.0	73.5
2011	23.2	17.2	74.3
2012	[a] 24.5	[a] 18.5	[a] 75.6

[a] Preliminary data

Sources: Exelon 2013a, 2013b

Exelon Generation pays property taxes directly to Ogle County in accordance with tax bills received from Ogle County each year. Each bill shows all of the taxing bodies that are imposing a tax on each tax parcel. As the Byron property is large, some of its tax parcels fall within multiple taxing districts. Exelon Generation, however, has no control over how the tax money is allocated to the respective taxing districts. Each district has the ability to levy against all taxpayers within its respective district according to its own charter and according to State law. The Ogle County Treasurer then allocates the tax money according to predetermined levies once all taxes have been collected (Exelon 2013b).

The following tables show the total levy for each taxing body and the amount paid by Exelon Generation to each taxing body. The tables also show the percentage of total revenue represented by Exelon Generation's tax payment for the tax years 2011 and 2012 (see Tables 3–30 and 3–31, respectively). The 2012 data are preliminary when submitted by the applicant, and the total levies for any one of the taxing bodies within Ogle County may change when the tax year closes (Exelon 2013b).

Although variations in tax levies are not completely under its control, Exelon Generation expects that Byron's annual property tax payments will remain relatively constant through the license renewal period. In 1998, Byron replaced the Unit 1 steam generators. Because the replacement was considered one-for-one, the Station's assessed value was unaffected. Exelon expects that any future one-for-one replacement projects will also not affect the station's assessed value (Exelon 2013a).

Table 3–30. 2011 Property Tax Payment Comparison, Each Taxing District Individually

Taxing Body	Total Taxing District Levy (dollars)	Taxing District Portion of Byron Property Tax Payment (dollars)	Byron Payment as Percent of Taxing District Levy (percent)
Rockvale Township Road District	439,398.38	412,078.70	94
Rockvale Township	162,893.90	147,867.78	91
Oregon Park District	2,426,968.19	1,945,577.49	80
Byron Library District	985,733.24	790,179.58	80
Byron Fire District	2,847,882.53	2,137,067.08	75
Byron Forest Preserve	2,235,104.08	1,664,691.42	75
Byron School Unit 226	23,175,260.74	17,219,124.59	74
Byron Museum District	107,847.70	80,314.40	74
Rock Valley Community College 511	3,996,316.29	2,131,800.53	53
Ogle County	10,895,856.26	3,500,490.42	32
Oregon School Unit 220	9,954,055.80	608,129.98	6
Kishwaukee College 523	2,178,105.74	70,351.06	3
Marion Township Road	280,324.97	7,001.20	2
Marion Township	202,895.79	4,815.41	2
Stillman Valley Fire District	564,747.94	6,558.42	1
Byron Park District	535,352.10	5,599.27	1
Meridian Unit 223	7,668,245.10	28,676.18	<1
Julia Hull District Library	216,840.52	746.90	<1
Oregon Fire District	393,225.48	511.33	<1
City of Byron	680,358.62	789.59	<1
Byron Township Road	531,168.42	359.68	<1
Byron Township	197,888.03	121.79	<1

Source: Exelon 2013a

Table 3–31. 2012 Property Tax Payment Comparison, Each Taxing District Individually

Taxing Body	Total Taxing District Levy (dollars)	Taxing District Portion of Byron Property Tax Payment (dollars)	Byron Payment as Percent of Taxing District Levy (percent)
Rockvale Township Road District	473,936.19	433,301.95	91
Rockvale Township	170,402.82	155,781.07	91
Oregon Park District	2,592,707.40	2,053,432.47	79
Byron Library District	1,100,021.40	832,826.26	76
Byron Fire District	2,849,570.86	2,173,799.08	76
Byron Forest Preserve	2,723,877.90	2,063,496.61	76
Byron School Unit 226	24,531,412.11	18,540,024.03	76
Byron Museum District	107,904.13	81,743.99	76
Rock Valley Community College 511	3,983,228.58	2,186,116.75	55
Ogle County	11,050,901.32	3,696,958.55	33
Oregon School Unit 220	9,727,868.75	636,845.75	7
Kishwaukee College 523	2,408,561.88	81,556.77	3
Marion Township Road	275,794.50	6,764.70	2
Marion Township	203,166.03	4,835.00	2
Stillman Valley Fire District	546,071.62	6,333.17	1
Byron Park District	537,766.04	5,622.09	1
Meridian Unit 223	7,638,510.57	28,042.48	<1
Julia Hull District Library	227,365.20	721.32	<1
Oregon Fire District	407,275.39	556.99	<1
City of Byron	664,602.29	814.93	<1
Byron Township Road	548,577.95	366.86	<1
Byron Township	205,197.50	141.50	<1

Source: Exelon 2013a

3.10.6 Local Transportation

Major freeways serving Ogle County include interstates I-39 and I-88. Other major roadways serving the county are north/south state routes 2, 26, and 251, U.S. Highway 52, and east/west state routes 38, 64, and 72. Road access to Byron is via German Church Road (also known as County Highway 2), which runs northeast-southwest. Byron has two access roads, a northern entrance and a southern entrance, both of which intersect German Church Road approximately 3 to 4 mi (5 to 6 km) southwest of the City of Byron. The northern access road provides primary access to the site for employees. In the City of Byron, German Church Road intersects County Highway 33 and State route Illinois (IL) 72, at a single intersection. State route IL 72 travels east and north at that intersection. County Highway 33 travels west. German Church Road intersects State route IL 64 at a location 5 to 6 mi (8 to 9.5 km) south of the Byron entrance. Employees traveling from the north use a combination of State routes IL 2, IL 72, County Highway 33, and North German Church Road to reach the station. Employees traveling from the south use a combination of State routes IL 2, IL 64, and South German Church Road to reach the station.

Exelon Generation employees report that there has been no traffic congestion in the area during normal operations (Exelon 2013a). During major refueling or maintenance outages, both entrances are opened to alleviate potential traffic congestion. During the first weeks of an outage, some traffic backups occur at the northern entrance because the back shifts have not yet started and most outage workers are on the first shift. Once the back shifts start, traffic congestion usually abates. Byron maintenance crews add signage to warn drivers of temporary traffic congestion in the area. Byron employees do not recall any congestion issues during the 1998 steam generator replacement project (Exelon 2013a).

Table 3-32 lists commuting routes to the Byron site and average annual daily traffic (AADT) volume values. The AADT values represent traffic volumes for a 24-hour period factored by both the day of the week and the month of the year.

Table 3–32. Major Commuting Routes in the Vicinity of Byron: 2012 AADT

Roadway and Location	Average Annual Daily Traffic (AADT)[a]
The section of North German Church Road between the station entrance and IL 72	1,300 – 2,250
On County Highway 33, near its intersection with North German Church Road	2,800
On IL 72, just east of its intersection with North German Church Road	12,300
The section of South German Church Road between the station entrance and IL 64	750 – 1,350
On IL 64, just east of the intersection with South German Church Road	[b]4,200
On IL 64, just west of the intersection with South German Church Road	[b]4,900

[a] Unless otherwise indicated, all AADTs represent traffic volume during the average 24-hour day during 2012.
[b] AADTs in 2011

Source: IDOT 2014

3.11 Human Health

3.11.1 Radiological Exposure and Risk

As required by NRC regulation, 10 CFR 20.1101, Exelon has a radiation protection program designed to protect onsite personnel, including employees, contractor employees, visitors, and offsite members of the public from radiation and radioactive material generated at Byron.

The radiation protection program is extensive and includes, but is not limited to the following:

- Organization and Administration (i.e., a Radiation Protection Manager who is responsible for the program and having trained and qualified workers),
- Implementing procedures,
- ALARA Program to minimize dose to workers and members of the public,
- Dosimetry Program (i.e., measure radiation dose of plant workers),
- Radiological Controls (i.e., protective clothing, shielding, filters, respiratory equipment, and individual work permits with specific radiological requirements),
- Radiation Area Entry and Exit Controls (i.e., locked or barricaded doors, interlocks, local and remote alarms, personnel contamination monitoring stations),
- Posting of Radiation Hazards (i.e., signs and notices alerting plant personnel of potential hazards),
- Record Keeping and Reporting (i.e., documentation of worker dose and radiation survey data),
- Radiation Safety Training (i.e., classroom training and use of mockups to simulate complex work assignments),
- Radioactive Effluent Monitoring Management (i.e., control and monitor radioactive liquid and gaseous effluents released into the environment),
- Radioactive Environmental Monitoring (i.e., sampling and analysis of environmental media, such as air, water, vegetation, food crops, direct radiation, and milk to measure the levels of radioactive material in the environmental that may impact human health), and
- Radiological Waste Management (i.e., control, monitor, process, and dispose of radioactive solid waste).

Regarding the radiation exposure to Byron personnel, the NRC staff reviewed the data contained in NUREG–0713, *Occupational Radiation Exposure at Commercial Nuclear Power Reactors and Other Facilities 2011: Forty-Fourth Annual Report (NUREG–0713, Volume 33*) (Lewis et al. 2013). This report, which was the most recent available at the time of this review, summarizes the occupational exposure data through 2011 that are maintained in the NRC's Radiation Exposure Information and Reporting System database. Nuclear power plants are required by 10 CFR 20.2206 to report their occupational exposure data to the NRC annually.

NUREG–0713 calculates a 3-year average collective dose per reactor for all nuclear power reactors licensed by the NRC. The 3-year average collective dose is one of the metrics that the NRC uses in the Reactor Oversight Program to evaluate the applicant's ALARA program. Collective dose is the sum of the individual doses received by workers at a facility licensed to use radioactive material over a 1-year time period. There are no NRC or EPA standards for collective dose. Based on the data for operating PWRs like those at Byron, the average annual collective dose per reactor was 59.71 person-rem. In comparison, Byron had a reported annual collective dose per reactor of 63.99 person-rem.

In addition, as reported in NUREG–0713, for 2011, no worker at Byron received an annual dose greater than 2.0 rem (0.02 sievert (Sv)), which is well below the NRC occupational dose limit of 5.0 rem (0.05 Sv) in 10 CFR 20.1201.

3.11.2 Chemical Hazards

The use, storage, and discharge of chemicals, biocides, and sanitary wastes, as well as minor chemical spills are regulated by State and Federal environmental agencies. Chemical hazards to plant workers resulting from continued operations and refurbishment associated with license renewal are expected to be minimized by the applicant's implementing good industrial hygiene practices as required by permits and Federal and State regulations. Plant discharges of these chemical and sanitary wastes are monitored and controlled as part of the plant's NPDES permit process to minimize impacts to the public and the environment. In addition, proposed changes in the use of cooling water treatment chemicals would require review by the plant's NPDES permit-issuing authority and possible modification of the existing NPDES permit, including examination of the human health effects of the change.

The use, storage, and discharge of chemicals and sanitary wastes at Byron are controlled in accordance with Exelon's fleet chemical control procedures and site-specific chemical spill prevention plans. Exelon's Spill Prevention, Control and Countermeasure plan serves as the site's hazardous waste contingency plan. Chemical wastes are controlled and managed in accordance with Exelon's waste management procedure. These plant procedures and plans are designed to prevent and minimize the potential for a chemical or hazardous waste release that could impact workers, members of the public, and the environment (Exelon 2003).

3.11.3 Microbiological Hazards

Radioactive Waste Nuclear plants that have cooling towers and that discharge thermal effluents to cooling ponds, lakes, canals, or rivers, such as Byron, have the potential to promote the increased growth of thermophilic microorganisms, which could result in adverse health effects for plant workers and the public. Microorganisms of particular concern include several types of bacteria (*Legionella* spp., *Salmonella* spp., *Shigella* spp., and *Pseudomonas aeruginosa*) and the free-living amoeba *Naegleria fowleri*.

Nuclear plant workers can be exposed to *Legionella* spp. when performing maintenance activities on plant cooling systems if workers inhale cooling tower vapors, because vapors are often within the optimum temperature range for *Legionella* growth. Plant personnel most likely to come in contact with *Legionella* aerosols would be workers who clean biofilms off of condenser tubes, cooling towers, and related system components or equipment. Exposure of the public to *Legionella* from nuclear plant operations is generally not a concern, because *Legionella* exposure would be confined to a small area of the site within the protected area.

The public can be exposed to the thermophilic microorganisms *Salmonella*, *Shigella*, *P. aeruginosa*, and *N. fowleri* during swimming, boating, or other recreational uses of fresh water. If a nuclear plant's thermal effluent enhances the growth of thermophilic microorganisms, recreational users could experience an elevated risk of exposure when using waters near the plant's discharge.

Thermophilic Microorganisms of Concern

Legionella is a genus of common warm water bacteria that occurs in lakes, ponds, and other surface waters, as well as some groundwater sources and soils. The bacteria are pathogenic to humans when aerosolized and inhaled into the lungs. Approximately 2 to 5 percent of those exposed in this way to *Legionella* develop an acute bacterial infection of the lower respiratory tract known as Legionnaires' disease (Pearson 2003). Optimal growth occurs in stagnant surface waters with biofilms or slimes that range in temperature from 35 to 45 °C (95 to 113 °F), though the bacteria can persist in waters from 20 to 50 °C (68 to 122 °F) (Pearson 2003). Elderly and immunocompromised individuals are most susceptible to Legionnaires' disease

(Pearson 2003). According to data from the Centers for Disease Control and Prevention (CDC 2011a) from 2000 through 2009, New England and Middle Atlantic states generally have the highest number of reported legionellosis cases each year.

Approximately 2,000 serotypes of *Salmonella* spp. cause the bacterial infection salmonellosis in humans. Of these, the serotypes Typhimurium and Enteritidis are the most common in the United States (CDC 2010a). Salmonellosis is most common in summer months, and it is transmitted through contact with food, water, or animals contaminated with human or animal feces (CDC 2010a). The bacteria have an optimal growth temperature of 98.6 °F (37 °C) but can grow at temperatures ranging from 43 to 115 °F (6 to 46 °C) (Albrecht 2013a). Studies examining the persistence of *Salmonella* spp. outside of a host have found that *Salmonella* can survive for several months in water and in aquatic sediments (Moore et al. 2003).

Shigella is a genus of bacteria species that causes shigellosis (i.e., bacterial dysentery), which is spread through consuming fecal-contaminated food or water or by swimming in contaminated water. Its optimum growth temperature is 37 °C (98.6 °F), though it can grow in water temperatures ranging from 10 to 40 °C (50 to 104 °F) (Albrecht 2013b). Shigellosis is most common in summer months and among toddlers age 2 to 4 in childcare settings (CDC 2013e).

Pseudomonas aeruginosa is a free-living bacterium found in soil, water, and plant surfaces. It is most commonly linked to infections transmitted in healthcare settings. However, as a waterborne pathogen, it can cause ear infections (i.e., “swimmer’s ear”), eye infections, and skin rashes after exposure to contaminated hot tubs, swimming pools, or other recreational waters (CDC 2013a). Its optimum growth temperature is 37 °C (98.6 °F), though it can grow at temperatures as high as 42 °C (107.6 °F) (Todar 2004). *P. aeruginosa* almost exclusively infects immunocompromised individuals or already injured or inflamed sites on the skin (Todar 2004).

Naegleria fowleri is a free-living amoeba that occurs in warm lakes, rivers, or hot springs. It is the causative agent of human primary amoebic meningoencephalitis (PAM). Infection occurs when contaminated freshwater enters the nose, and the amoeba migrates to brain tissue; the ensuing illness is usually fatal (CDC 2013b). *N. fowleri* grows best at higher temperatures up to 46 °C (115 °F) (CDC 2013b), though it has also been isolated from thermally altered waters surrounding power plant discharges at temperatures ranging from 35 to 41 °C (95 to 105.8 °F) (Stevens et al. 1977).

Prevalence of Waterborne Diseases Associated with Recreational Waters

From 2002 through 2011, the CDC (2003, 2004a, 2005, 2006a, 2007, 2008a, 2009, 2010b, 2011b, 2012) reported an average of 2,774 cases of Legionnaires’ disease per year, of which between 28 and 151 per year were reported from Illinois. Although *Legionella* is often present in the cooling tower vapors of power plants, cases of Legionnaires’ disease from this type of exposure are rare due to workers’ use of appropriate respiratory protection.

The Illinois Department of Public Health (IDPH) indicates that approximately 1,500 to 2,000 cases of salmonellosis are reported in the State each year (IDPH 2009). However, the overwhelming majority of salmonellosis cases are foodborne (CDC 2010a). The CDC reports biannually on waterborne disease outbreaks associated with recreational waters. A review of the past 10 available data years (1999 through 2008) of these reports indicates that no outbreaks or cases of waterborne *Salmonella* infection from recreational waters occurred in the United States during this timeframe (CDC 2002, 2004b, 2006b, 2008b, 2011c). From 2006 to 2013, all CDC-reported salmonellosis outbreaks have been caused by contaminated produce, meats, or prepared foods or through contact with contaminated animals (CDC 2013d).

Approximately 1,300 confirmed cases of shigellosis are reported in Illinois each year (IDPH 2013). CDC reports (2002, 2004b, 2006b, 2008b, 2011c) indicate that less than a dozen shigellosis outbreaks have been attributed to lakes, reservoirs, and other recreational waters in the past 10 available data years (1999 through 2008). None of these cases were in Illinois.

Infections attributed to *Pseudomonas aeruginosa* are most commonly contracted in pools, spas, and hot tubs. No cases of infection linked to contaminated recreational waters in the United States have been reported within the past 10 available data years (1999 through 2008) (CDC 2002, 2004b, 2006b, 2008b, 2011c).

The *N. fowleri*-caused disease, PAM, is rare in the United States. Since 1962, between zero and eight cases of PAM have been reported to the CDC annually, and no cases have been reported in Illinois (CDC 2013c)

3.11.4 Electromagnetic Fields

Based on the GEIS, the Commission found that electric shock resulting from direct access to energized conductors or from induced charges in metallic structures has not been found to be a problem at most operating plants and generally is not expected to be a problem during the license renewal term. However, a site-specific review is required to determine the significance of the electric shock potential along the portions of the transmission lines that are within the scope of this SEIS.

In the GEIS, the NRC found that without a review of the conformance of each nuclear plant transmission line with National Electrical Safety Code® (NESC®) criteria, it was not possible to determine the significance of the electric shock potential (IEEE 2002). Evaluation of individual plant transmission lines is necessary because the issue of electric shock safety was not addressed in the licensing process for some plants. For other plants, land use in the vicinity of transmission lines may have changed, or power distribution companies may have chosen to upgrade line voltage. To comply with 10 CFR 51.53(c)(3)(ii)(H), the applicant must provide an assessment of the impact of the proposed action on the potential shock hazard from the transmission lines if the transmission lines that were constructed for the specific purpose of connecting the plant to the transmission system do not meet the recommendations of the NESC for preventing electric shock from induced currents. The NRC uses the NESC criteria and the applicant's adherence to those criteria during the current operating license as its baseline to assess the potential human health impact of the induced current from an applicant's transmission lines. As discussed in the GEIS, the issue of electric shock is of small significance for transmission lines that are operated in adherence with the NESC criteria.

Byron's associated transmission lines were designed and constructed in accordance with the Illinois Commerce Commission General Order 160 and the sixth edition of the NESC. ComEd is the owner and operator of the transmission lines and has surveillance and maintenance procedures to assure that current ground clearances will not change. ComEd performs routine inspections and aerial patrols to check for encroachments, broken conductors, or any other evidence of clearance issues.

Exelon used the Power Line Systems Software program (PLS-CADD™) to analyze the three-dimensional models created from the LIDAR (Light Detection and Ranging) data and calculate the potential for induced shock effects. All electromagnetic field calculations in PLS-CADD are based on the Electric Power Research Institute methodology. Of the three 345-kV transmission lines studied, Exelon reported that none exceed the 5-milliampere NESC standard (Exelon 2013a).

3.11.5 Other Hazards

Two additional human health issues are addressed in this section: physical occupational hazards and electric shock hazards.

Nuclear power plants are industrial facilities that have many of the typical occupational hazards found at any other electric power generation utility. Workers at or around nuclear power plants would be involved in some electrical work, electric power line maintenance, repair work, and maintenance activities and exposed to some potentially hazardous physical conditions (e.g., falls, excessive heat, cold, noise, electric shock, and pressure). The issue of physical occupational hazards is generic to all nuclear power plants.

The Occupational Safety & Health Administration (OSHA) is responsible for developing and enforcing workplace safety regulations. OSHA was created by the Occupational Safety and Health Act of 1970 (OSH Act) (29 U.S.C. 651 et seq.), which was enacted to safeguard the health of workers. With specific regard to nuclear power plants, plant conditions that result in an occupational risk, but do not affect the safety of licensed radioactive materials, are under the statutory authority of OSHA rather than the NRC as set forth in a Memorandum of Understanding (53 FR 42950, October 31, 1988) between the NRC and OSHA. Occupational hazards can be minimized when workers adhere to safety standards and use appropriate protective equipment; however, fatalities and injuries from accidents can still occur.

Byron maintains an occupational safety program in accordance with OSHA regulations for its workers (Exelon 2013a).

3.12 Environmental Justice

Environmental Justice Under Executive Order (EO) 12898 (59 FR 7629), Federal agencies are responsible for identifying and addressing, as appropriate, disproportionately high and adverse human health and environmental impacts on minority and low-income populations. In 2004, the Commission issued a *Policy Statement on the Treatment of Environmental Justice Matters in NRC Regulatory and Licensing Actions* (69 FR 52040), which states, "The Commission is committed to the general goals set forth in EO 12898, and strives to meet those goals as part of its National Environmental Policy Act (NEPA) review process."

The Council on Environmental Quality (CEQ) provides the following information in *Environmental Justice: Guidance Under the National Environmental Policy Act* (CEQ 1997):

> **Disproportionately High and Adverse Human Health Effects.**
>
> Adverse health effects are measured in risks and rates that could result in latent cancer fatalities, as well as other fatal or nonfatal adverse impacts on human health. Adverse health effects may include bodily impairment, infirmity, illness, or death. Disproportionately high and adverse human health effects occur when the risk or rate of exposure to an environmental hazard for a minority or low-income population is significant (as employed by NEPA) and appreciably exceeds the risk or exposure rate for the general population or for another appropriate comparison group.
>
> **Disproportionately High and Adverse Environmental Effects.**
>
> A disproportionately high environmental impact that is significant (as employed by NEPA) refers to an impact or risk of an impact on the natural or physical environment in a low-income or minority community that appreciably exceeds the environmental impact on the larger community. Such effects may include ecological, cultural, human health, economic, or social impacts. An adverse environmental impact is an impact that is determined to be both harmful and

> significant (as employed by NEPA). In assessing cultural and aesthetic environmental impacts, impacts that uniquely affect geographically dislocated or dispersed minority or low-income populations or American Indian tribes are considered.

The environmental justice analysis assesses the potential for disproportionately high and adverse human health or environmental effects on minority and low-income populations that could result from the operation of Byron during the renewal term. In assessing the impacts, the following definitions of minority individuals and populations and low-income population were used (CEQ 1997):

> **Minority individuals**
>
> Individuals who identify themselves as members of the following population groups: Hispanic or Latino, American Indian or Alaska Native, Asian, Black or African American, Native Hawaiian or Other Pacific Islander, or two or more races, meaning individuals who identified themselves on a Census form as being a member of two or more races, for example, White and Asian.
>
> **Minority populations**
>
> Minority populations are identified when (1) the minority population of an affected area exceeds 50 percent or (2) the minority population percentage of the affected area is meaningfully greater than the minority population percentage in the general population or other appropriate unit of geographic analysis.
>
> **Low-income population**
>
> Low-income populations in an affected area are identified with the annual statistical poverty thresholds from the Census Bureau's Current Population Reports, Series P60, on Income and Poverty.

3.12.1 Minority Population

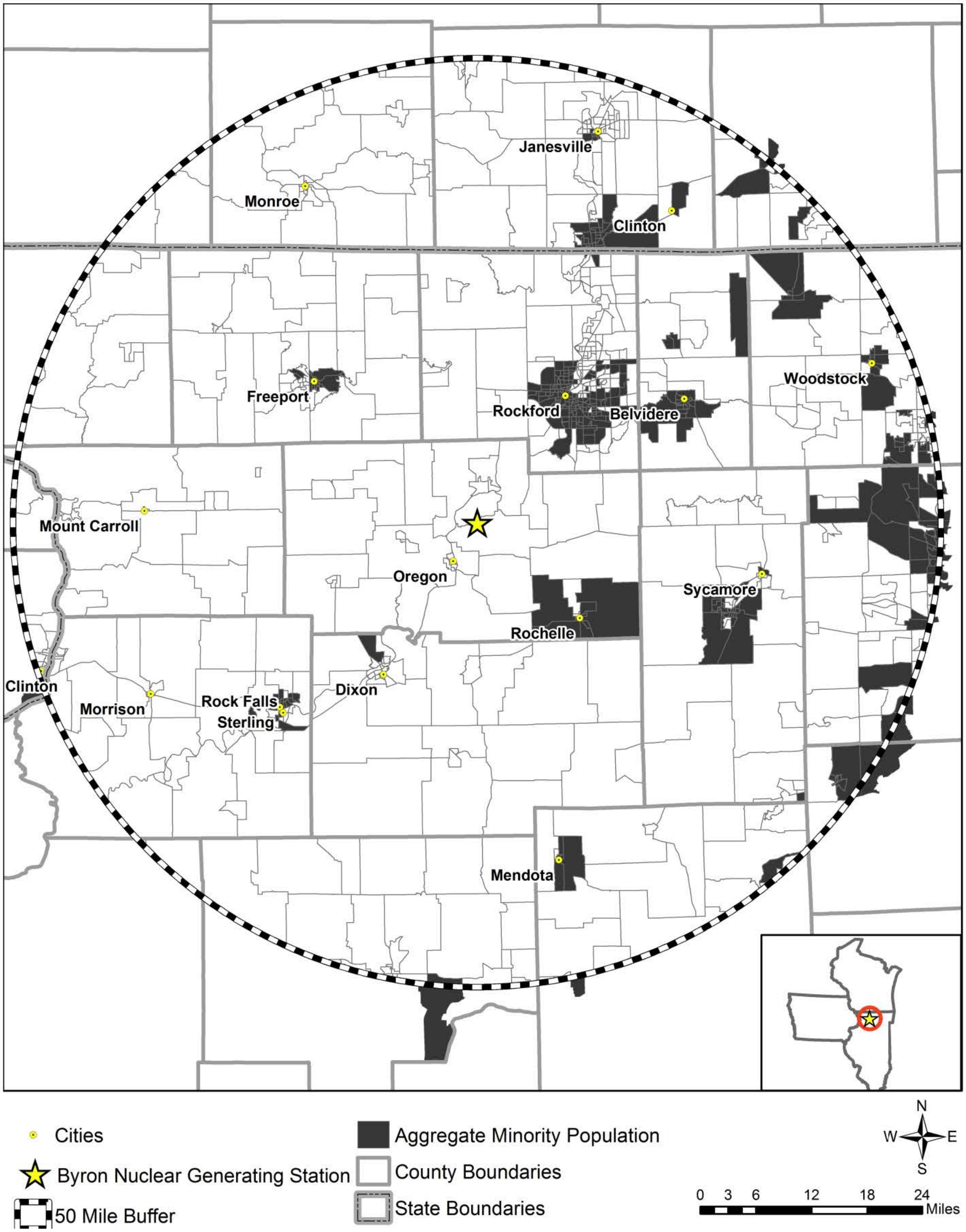
According to 2010 Census data, approximately 20 percent of the population residing within a 50-mi (80-km) radius of Byron identified themselves as minority individuals. The largest minority group was Hispanic or Latino (of any race) (11 percent), followed by Black or African-American (5 percent) (USCB 2014a).

According to 2010 Census data, minority populations in the socioeconomic ROI (Lee, Ogle, and Winnebago counties) composed 23.7 percent of the total two-county population (see Table 3–19). Figure 3–13 shows predominantly minority population block groups, using 2010 Census data for race and ethnicity, within a 50-mi (80-km) radius of Byron.

Census block groups were considered minority population block groups if the percentage of the minority population within any block group exceeded 20 percent (the percent of the minority population within the 50-mi (80–km) radius of Byron). A minority population exists if the percentage of the minority population within the block group is meaningfully greater than the minority population percentage in the 50-mi (80-km) radius. Approximately 356 of the 979 census block groups located within the 50-mi (80-km) radius of Byron have meaningfully greater minority populations (USCB 2014f).

As shown in Figure 3–13, the nearest minority population block groups (race and ethnicity) are mostly clustered near Rockford, Rochelle, and Freeport, Illinois. None of the block groups near Byron have meaningfully greater minority populations.

1 **Figure 3–13. Minority Block Groups Within a 50-mi Radius of Byron**



2

3 Source: USCB 2014f

3.12.2 Low-Income Population

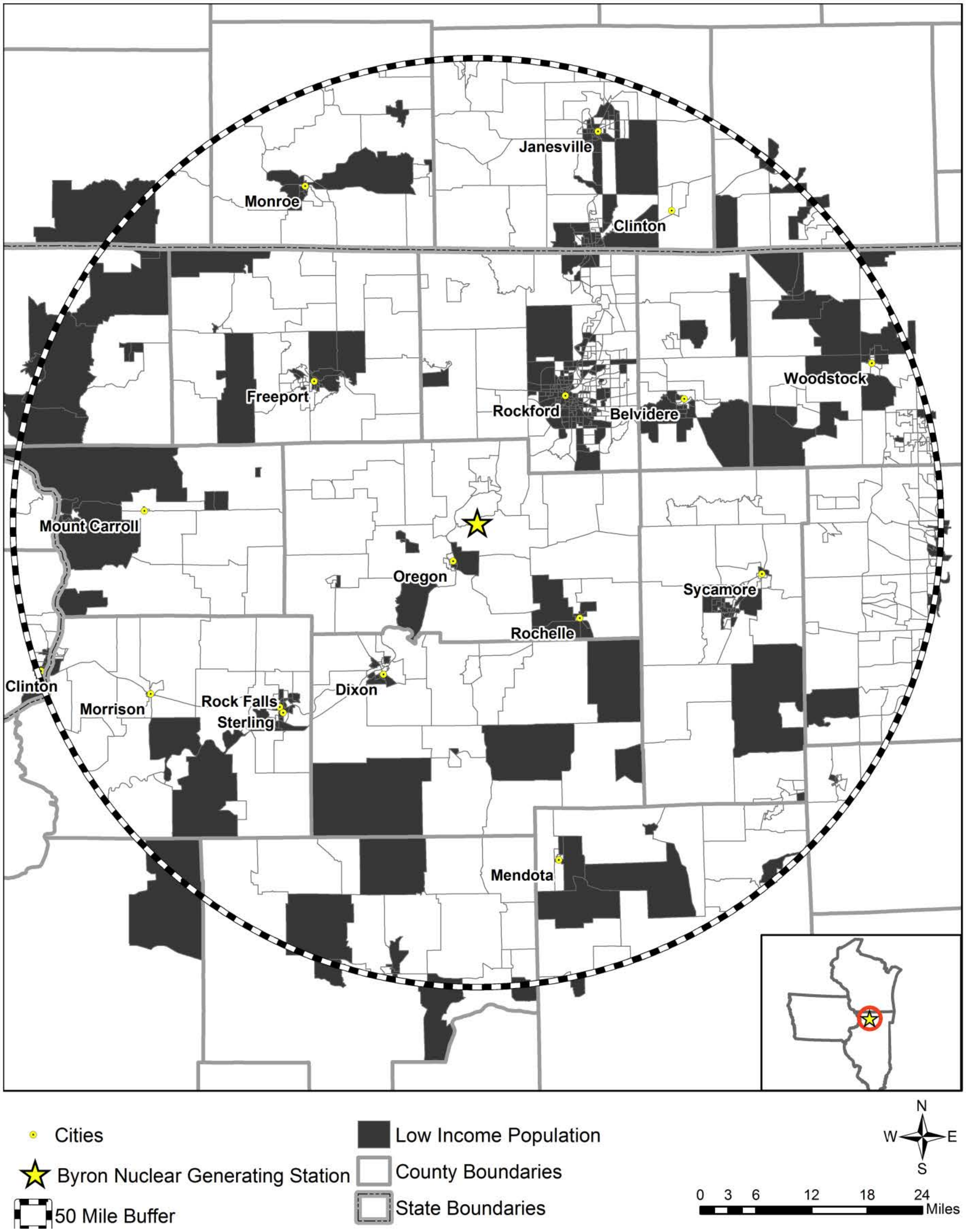
According to the USCB's 2008–2012 American Community Survey 5 Year Estimates, an average of 7.7 percent of families and 11.8 percent of individuals residing within a 50-mi (80-km) radius of Byron were identified as living below the Federal poverty threshold (USCB 2014a). The 2012 Federal poverty threshold was $23,942 for a family of four.

According to the USCB's 2008–2012 American Community Survey 5 Year Estimates, 10 percent of families and 13.7 percent of individuals in Illinois were living below the Federal poverty threshold in 2012, and the median household income for Illinois was $56,853 (USCB 2014a). People living in the socioeconomic ROI (Lee, Ogle, and Winnebago Counties) had median household incomes below the State average. Winnebago County had the lowest median household income average ($47,573) of the three counties and the highest percentages of persons (17 percent of individuals and 12.8 percent of families) living below the poverty level. Lee and Ogle Counties had median household income averages of $50,342 and $55,590, respectively, and each had 10 percent of individuals and 7.4 percent of families, respectively, living below the poverty level (USCB 2014a).

Figure 3–14 shows the location of predominantly low-income population block groups within a 50-mi (80-km) radius of Byron. Census block groups were considered low-income population block groups if the percentage of individuals living below the Federal poverty threshold within any block group exceeded 11.8 percent (the percent of the individuals living below the Federal poverty threshold within the 50-mi (80-km) radius of Byron). Approximately 337 of the 979 census block groups located within the 50-mi (80-km) radius of Byron have meaningfully greater low-income populations (USCB 2014f).

As shown in Figure 3–14, the nearest low-income population block groups are mostly clustered near Rockford, Rochelle, and Freeport, Illinois. None of the block groups encompassing Byron have meaningfully greater low-income populations.

1 **Figure 3–14. Low-Income Block Groups Within a 50-mi (80-km) Radius of Byron**



2

3 Source: USCB 2014f

3.13 Waste Management and Pollution Prevention

3.13.1 Radioactive Waste

As discussed in Section 3.1.4 of this SEIS, Byron uses liquid, gaseous, and solid waste processing systems to collect and treat, as needed, radioactive materials produced as a byproduct of plant operations. Radioactive materials in liquid and gaseous effluents are reduced prior to being released into the environment so that the resultant dose to members of the public from these effluents is well within NRC and EPA dose standards. Radionuclides that can be efficiently removed from the liquid and gaseous effluents prior to release are converted to a solid waste form for disposal in a licensed disposal facility.

3.13.2 Nonradioactive Waste

Waste minimization and pollution prevention are important elements of operations at all nuclear power plants. The applicants are required to consider pollution prevention measures as dictated by the Pollution Prevention Act of 1990 (PPA) (Public Law (PL) 101-508) and Resource Conservation and Recovery Act (RCRA) (PL 94-580).

As described in Section 3.1.5, Byron has a nonradioactive waste management program to handle this nonradioactive waste. In addition to managing its nonradioactive waste, Exelon has programs in place to minimize the generation of this waste. Byron implements a hazardous waste minimization plan to reduce, to the extent feasible, waste generated, treated, accumulated, or disposed (Exelon 2003). This plan documents waste streams that have been eliminated and lists current waste streams generated at the facility (Exelon 2003). The plan is updated annually and used in conjunction with plant waste management procedures on solid, special, hazardous, mixed waste, and chemicals to control and minimize waste generation to the maximum extent practicable.

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4.0 ENVIRONMENTAL CONSEQUENCES AND MITIGATING ACTIONS

4.1 Introduction

In this chapter, the U.S. Nuclear Regulatory Commission (NRC) evaluates the environmental consequences of the proposed action (i.e., license renewal of Byron Station, Units 1 and 2 (Byron)), including the (1) impacts associated with continued operations similar to those that have occurred during the current license terms; (2) impacts of various alternatives to the proposed action; (3) impacts from the termination of nuclear power plant operations and decommissioning after the license renewal term (with emphasis on the incremental effect caused by an additional 20 years of operation); (4) impacts associated with the uranium fuel cycle; (5) impacts of postulated accidents (design-basis accidents (DBAs) and severe accidents); (6) cumulative impacts of the proposed action; and (7) resource commitments associated with the proposed action, including unavoidable adverse impacts, the relationship between short-term use and long-term productivity, and irreversible and irretrievable commitment of resources. The NRC also considers new and potentially significant information on environmental issues related to the impacts of operation during the renewal term.

NUREG-1437, *Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear* Plants (NRC 1996, 1999, 2013a) identifies 78 issues to be evaluated in the license renewal environmental review process. This supplemental environmental impact statement (SEIS) supplements the information provided in the GEIS. Generic issues (Category 1) rely on the analysis presented in the GEIS, unless otherwise noted. Applicable site-specific issues (Category 2) have been analyzed for Byron and assigned a significance level of SMALL, MODERATE, or LARGE. Section 1.4 of this SEIS provides an explanation of the criteria for Category 1 and Category 2 issues, as well as the definitions of SMALL, MODERATE, and LARGE. Resource-specific impact significance level definitions are provided where applicable.

4.2 Land Use and Visual Resources

This section describes the potential impacts of the proposed action (license renewal) and alternatives to the proposed action on land use and visual resources.

4.2.1 Proposed Action

Section 3.2 of this SEIS describes land use and visual resources in the vicinity of the Byron site. The four generic (Category 1) issues that apply to land use and visual resources during the proposed license renewal period appear in Table 4–1. The GEIS (NRC 2013a) discusses these issues in Section 4.2.1. The GEIS does not identify any site-specific (Category 2) land use or visual resource issues.

The NRC staff did not identify any new and significant information related to the generic (Category 1) issues listed above during the review of the applicant's Environmental Report (ER) (Exelon 2013a), the site audit, or the scoping process. Therefore, the NRC expects no impacts associated with these issues beyond those discussed in the GEIS. The GEIS concludes that the impact level for each of these issues is SMALL.

Table 4–1. Land Use and Visual Resources Issues

Issue	GEIS Section	Category
Land Use		
Onsite land use	4.2.1.1	1
Offsite land use	4.2.1.1	1
Offsite land use in transmission line right-of-ways (ROWs)[a]	4.2.1.2	1
Visual Resources		
Aesthetic impacts	4.2.1.2	1

[a] This issue applies only to the inscope portion of electric power transmission lines, which are defined as transmission lines that connect the nuclear power plant to the substation where electricity is fed into the regional power distribution system and transmission lines that supply power to the nuclear plant from the grid.

Source: Table B-1 in Appendix B, Subpart A, to 10 CFR Part 51; NRC 2013a

4.2.2 No-Action Alternative

4.2.2.1 Land Use

If Byron were to shut down, the impacts to land use would remain similar to those during operations until the plant is fully decommissioned. Temporary buildings and staging or laydown areas may be required during large component and structure dismantling. Byron is likely to have sufficient space within previously disturbed areas for these needs, and therefore, no additional land would need to be disturbed that would result in changes to current land uses. In NUREG–0586, *Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities, Supplement 1*, NRC (2002) concludes generically that land use impact during decommissioning activities would be SMALL. The GEIS (NRC 2013a) notes that land use impacts could occur in other areas beyond the immediate nuclear plant site as a result of the no-action alternative if new power plants are needed to replace lost capacity. The NRC staff did not identify any impacts that may result at Byron beyond those discussed in NUREG–0586. Thus, the NRC staff concludes that the impacts of the no-action alternative on land use during the proposed license renewal term would be SMALL.

4.2.2.2 Visual Resources

If Byron were to shut down, visual resources impacts would remain similar to those experienced during operations until the site is fully decommissioned. The cooling towers, which create the largest visual impact, may eventually be dismantled, which would reduce the already SMALL impacts to visual resources that would occur during the proposed license renewal term. Thus, the NRC staff concludes that the impacts of the no-action alternative on visual resources would be SMALL.

4.2.3 New Nuclear Alternative

4.2.3.1 Land Use

The new nuclear alternative assumes that the new facility would be built at an existing nuclear or retired coal plant site within the region of influence (ROI) but outside of Illinois. Construction of the new nuclear plant would require an estimated 324 acres (ac) (131 hectares (ha)) for permanent buildings and facilities and an additional 31 ac (12.5 ha) for temporary facilities and laydown areas. The NRC staff assumes that this alternative would use existing onsite structures and previously disturbed areas to the extent practicable to minimize development of undisturbed land. Thus, this alternative would not significantly affect existing land uses. Given the land requirements, it is expected that some undisturbed lands would be affected, which would result in the conversion of natural areas to industrial areas. No additional land use changes would result from operation of the nuclear facility. The NRC staff concludes that the impacts to land use from construction and operation of a new nuclear alternative would be SMALL.

4.2.3.2 Visual Resources

Because the facility would be located on an existing site, visual resources impacts of most new buildings and infrastructure would be minimal. The construction of natural draft cooling towers would be the largest visual impact because both the towers themselves and the plume could be visible from a distance. The magnitude of this impact would vary based on the topography of the chosen site and surrounding area. The NRC staff concludes that the impacts to visual resources from construction and operation of a new nuclear alternative would be SMALL to MODERATE.

4.2.4 Integrated Gasification Combined Cycle (IGCC) Alternative

4.2.4.1 Land Use

The IGCC alternative assumes that the new facility would be built at an existing energy-producing site or a retired coal plant site in Illinois or another state within the ROI. The facility would require 2,000 ac (809 ha) of land to construct the facility. The NRC staff assumes that this alternative would use existing onsite structures and previously disturbed areas to the extent practicable to minimize new development in undisturbed areas. However, because the footprint of the facility would be large, it is likely that construction would require clearing of lands that are currently in a different land use, such as agricultural, forested, or other natural areas. The impacts of this would vary widely based on the specific site selection and land uses that would be lost due to construction. No additional land use changes would result from operation of the IGCC facility. The NRC staff concludes that the impacts to land use from construction and operations of an IGCC alternative would be SMALL to MODERATE, primarily due to the potential for conversion of land to industrial use during construction.

4.2.4.2 Visual Resources

Because the facility would be located on an existing site, visual resources impacts would be minimal. The mechanical draft cooling towers would likely not be significantly taller than other buildings on the site. However, the plume created from operation of the towers could create noticeable visual impacts depending on the topography of the chosen site and surrounding area. The NRC staff concludes that the impacts to visual resources from construction and operation of an IGCC alternative would be SMALL to MODERATE.

4.2.5 Natural Gas Combined-Cycle (NGCC) Alternative

4.2.5.1 Land Use

The NGCC alternative assumes that the facility would be built at an existing energy-producing site or a retired coal plant site in Illinois or another state within the ROI. The facility would require 94 ac (38 ha) of land for the plant and associated pipelines. Because the footprint of the facility would be relatively small, the entire construction footprint could likely be sited in already-developed areas of the site, which would minimize land use changes. No additional land use changes would result from operation of the NGCC facility. The NRC staff concludes that the impacts to land use from construction and operation of an NGCC alternative would be SMALL.

4.2.5.2 Visual Resources

Because the facility would be located on an existing site, visual resources impacts would be minimal. The mechanical draft cooling towers would likely not be significantly taller than other buildings on the site. However, the plume created from operation of the towers could create noticeable visual impacts depending on the topography of the chosen site and surrounding area. The NRC staff concludes that the impacts to land use and visual resources from construction and operation of an NGCC alternative would be SMALL to MODERATE.

4.2.6 Combination Alternative (NGCC, Wind, Solar)

4.2.6.1 Land Use

The NGCC component of this alternative would require the same amount of land as the NGCC alternative (94 ac (38 ha)), but the NGCC component would likely make better use of existing infrastructure because it would be sited at an existing power plant in Illinois or another state within the ROI and could use buildings and structures that are already in place and operational for the existing facility. Land use impacts would be similar to or less than those described in Section 4.2.5 for the NGCC alternative and would, therefore, be SMALL.

The wind component of the combination alternative would require 3,376 ac (1,366 ha) to 10,127 ac (4,098 ha) at sites across the ROI. However, the majority of this land would only be temporarily disturbed during construction. Permanently disturbed land would hold the wind turbines, access roads, and transmission lines. Land used for equipment laydown and turbine component assembly and erection could be returned to its original state. Given the large footprint of the wind component, land use could be affected. However, some land uses, such as agriculture, could continue once the wind turbines are operational. Land use impacts for the wind component would range from SMALL to MODERATE depending on the amount and types of land that would be affected by wind turbine construction.

The solar component would require 6,749 ac (2,731 ha) of land across the ROI. The majority of solar installations could be installed on building roofs at existing residential, commercial, or industrial sites or at larger standalone solar facilities, and thus, it is possible that little land would be required for construction. However, the exact magnitude of impacts on land use would depend on the amount of land that is required to be converted for construction of solar installations. Unlike wind power, solar-powered installations often cannot be colocated with existing land uses (such as in a crop-producing agricultural field). The impacts of the solar component of this alternative on land use would range from SMALL to MODERATE depending on the amount and types of land that would be affected by construction of the solar installations.

The NRC staff concludes that the impacts of the combination alternative on land use would be SMALL to MODERATE. This range is primarily the result of the variability in land required for the wind and solar components of the alternative.

4.2.6.2 Visual Resources

Visual resources impacts for the NGCC component of this alternative would be similar to or less than those described in Section 4.2.5 for the NGCC alternative and would, therefore, be SMALL. Visual resources would be significantly affected by construction of the wind component. Although specific effects would vary based on the topography and remoteness of the wind turbine locations, the visual impact of wind energy is often one of the most significant impacts and could range from MODERATE to LARGE. The visual impacts of the solar component would also vary based on the topography of the area but are expected to be minimal because individual solar installations are not tall or expansive, and many of the installations could be constructed on building roofs at existing residential, commercial, or industrial sites. Larger standalone solar facilities could have a greater visual impact depending on the location, but the staff finds that the impacts of the solar component would likely be SMALL overall. Overall, the NRC concludes that the impacts of the combination alternative on visual resources would be SMALL to LARGE.

4.2.7 Purchased Power

4.2.7.1 Land Use

The purchased power alternative would have wide-ranging impacts that are hard to specifically assess because this alternative could include a mixture of coal, natural gas, nuclear, and wind across many different sites in the ROI. This alternative would likely have little to no construction impacts because it would include power from already-existing power generating facilities. The construction of additional transmission lines could affect land uses if the lines require the clearing of new transmission line corridors. The types of operational impacts would be similar to the effects discussed in the preceding alternative sections. This alternative would be more likely to intensify already-existing effects at power generating facilities than create wholly new effects on land use. Existing facilities would likely have best management practices (BMPs) and other procedures in place to ensure that effects to the environment during operations are minimized. The NRC staff concludes that the impacts on land use from the purchased power alternative would be SMALL.

4.2.7.2 Visual Resources

The purchased power alternative would not result in the construction of any buildings or facilities or any other changes to existing visual resources. Thus, the NRC staff concludes that the purchased power alternative would have no impact on visual resources, and as such, it would be SMALL.

4.3 Air Quality and Noise

This section describes the potential impacts of the proposed action (license renewal) and alternatives to the proposed action on air quality and noise conditions.

4.3.1 Proposed Action

4.3.1.1 Air Quality

Section 3.3 describes the meteorological, air quality, and noise conditions in the vicinity of Byron Station. Part 51 of Title 10 of the *Code of Federal Regulations* (CFR), Subpart A, Appendix B, Table B-1 lists a summary of findings on National Environmental Policy Act (NEPA) issues for license renewal of nuclear power plants. Two Category 1 air quality issues are applicable to Byron Station, “air quality impacts (all plants)” and “air quality effects of transmission lines” (see Table 4–2). There are no Category 2 issues for air quality. The Category 1 issue “air quality effects of transmission lines” considers the production of ozone and oxides of nitrogen; the GEIS found that minute and insignificant amounts of ozone and nitrogen oxides are generated during transmission. The Category 1 issue “air quality impacts (all plants)” considers the air quality impacts from continued operation and refurbishment associated with license renewal. The GEIS concludes that the impact of refurbishment activities on air quality during the license renewal term would be SMALL for most plants, but could be cause for concern at plants located in or near air quality nonattainment or maintenance areas (NRC 2013a).

Table 4–2. Air Quality and Noise

Issue	GEIS Section	Category
Air quality impacts (all plants)	4.3.1.1	1
Air quality effects of transmission lines	4.3.1.1	1
Noise impacts	4.3.1.2	1

Source: Table B-1 in Appendix B, Subpart A, to 10 CFR Part 51

The NRC staff did not identify any new and significant information during the review of Exelon Generation Company, LLC's (Exelon's) ER (Exelon 2013a), the site audit, or during the scoping process. As a result, no information or impacts related to these issues were identified that would change the conclusions presented in the GEIS. Therefore, there are no impacts related to these issues beyond those discussed in the GEIS. The GEIS concludes that the impact level for each of these issues is SMALL.

4.3.1.2 Noise

One Category 1 noise issue is applicable to Byron Station, "noise impacts" (see Table 4–2). The 1996 GEIS (NRC 1996) concluded that noise was not a problem at operating plants and was not expected to be a problem at any nuclear plant during the license renewal term. The 2013 GEIS (NRC 2013a) did not identify new information that would alter this conclusion; therefore, impacts are expected to be SMALL. The NRC staff did not identify any new and significant information during the review of Exelon's ER (Exelon 2013a), the site audit, or during the scoping process. As a result, no information or impacts related to these issues were identified that would change the conclusions presented in the GEIS. Therefore, there are no impacts related to these issues beyond those discussed in the GEIS. The GEIS concludes that the impact level this issue is SMALL.

4.3.2 No-Action Alternative

4.3.2.1 Air Quality

When the plant stops operating, there would be a reduction in emissions from activities related to plant operation such as cooling towers, use of stationary combustion sources (such as diesel generators, auxiliary boilers, or fire pump), and vehicle traffic (such as workers and delivery). Therefore, if emissions decrease, the impact on air quality from shutdown of the Byron Station would be SMALL.

4.3.2.2 Noise

As discussed in Section 3.3.3 of this SEIS, the NRC staff found that the predicted total (background and station contributions combined) noise levels at nearby receptors from plant operation were a little higher than U.S. Environmental Protection Agency (EPA) guideline of 55 A-weighted decibels (dBA) day–night average sound level (L_{dn}) but well below the acceptable Department of Housing and Urban Development (HUD) L_{dn} guideline of 65 dBA. When the plant stops operating, there will be no noise from activities related to plant operation such as the use of cooling towers, switchyard/transformers, stationary combustion sources (such as diesel generators, auxiliary boilers, fire pump), and vehicle traffic (such as workers and delivery). In other words, noise levels around the site would return to the background levels that existed before the Byron Station was built. Therefore, if noise sources are reduced, the impact on ambient noise levels would also be reduced and would be SMALL.

4.3.3 New Nuclear Alternative

4.3.3.1 Air Quality

This alternative includes the construction and operation of two Westinghouse AP1000 reactors, each with an approximate generating capacity of 1,200 megawatts electric (MWe). Due to the moratorium preventing the construction of new nuclear power plants within Illinois, the new nuclear alternative would have to be located elsewhere in the ROI (Indiana, Iowa, Michigan, Missouri, Kentucky, and Wisconsin).

Construction of the new nuclear plant would result in temporary impacts on local air quality. During the construction phase, the primary sources of air emissions would consist of engine exhaust and fugitive dust emissions. Engine exhaust emissions would be from heavy construction equipment and commuter, delivery, and support vehicular traffic traveling within, to, and from the facility. Fugitive dust emissions would be from soil disturbances by heavy construction equipment (e.g., earthmoving, excavating, bulldozing), vehicle traffic on unpaved surfaces, concrete batch plant operations (if any), and wind erosion to a lesser extent. Air emissions include criteria pollutants (particulate matter (PM), NO_x, CO, and SO_2), volatile organic compounds (VOCs), hazardous air pollutants (HAPs), and greenhouse gases (GHGs). Small quantities of VOCs and HAPs emissions would be released from equipment refueling; organic solvents used in cleaning, onsite storage, and use of petroleum-based fuels; onsite maintenance of the heavy construction equipment; and certain painting and other construction-finishing activities.

A new nuclear plant site in the Midwest would likely be located on a relatively flat site and no heavy earthmoving activities, such as major cut-and-fill operations, would be needed. Air emissions would be intermittent and vary based on the level and duration of a specific activity throughout the construction phase. Construction lead times for nuclear plants are anticipated to be 7 years (NRC 2013a). Based on the State and Federal permits and regulated practices for managing air emissions from construction equipment and temporary stationary sources, controlling fugitive dust, and vehicle inspection and traffic management plans, the NRC staff expects that potential impacts on air quality from building a nuclear power plant would be minimal. Since air emissions from construction activities would be limited, local, and temporary, the NRC staff concludes that the overall air quality impacts associated with construction of a new nuclear alternative would be SMALL.

Operation of a new nuclear generating plant would result in similar air emissions to those of the existing Byron site. Nuclear power plants do not burn fossil fuels to generate electricity. Sources of air emissions include stationary combustion sources (e.g., emergency diesel generators, diesel-driven fire pumps, and auxiliary boilers), cooling towers (natural or mechanical draft cooling towers), and mobile sources (worker vehicles, onsite heavy equipment and support vehicles, and delivery of materials and disposal of wastes). Air pollutants emitted from stationary combustion sources (e.g., criteria pollutants, VOCs, HAPs, and GHGs) and from cooling towers (PM as drift) associated with operations of a nuclear power plant would be permitted in accordance with State and Federal regulatory requirements. As noted in Section 3.3, Byron maintains a Federally Enforceable State Operating Permit (also known as a "synthetic minor" air permit). A synthetic minor source has the potential to emit air pollutants in quantities at or above the major source threshold levels but has accepted Federally enforceable limitations to keep the emissions below such levels. Because air emissions would be similar for a new nuclear plant, the NRC staff expects similar air permitting conditions and regulatory requirements. Subpart P of 40 CFR Part 51.307 contains the visibility protection regulatory requirements, including the review of the new sources that may affect visibility in any Federal Class I area. If a new nuclear plant were located near a mandatory Class I area, additional air pollution control requirements may be required.

In general, most stationary combustion sources at a nuclear power plant would operate only for limited periods, often for periodic maintenance testing. Thus, emissions from stationary combustion sources would fall far below the threshold for major sources (100 U.S. short tons (t) per year) and the threshold for mandatory GHG reporting (25,000 metric tons (MT) per year) (see Table 3–1 of this SEIS for air emissions at Byron during operation). In contrast, cooling towers would operate continuously for the entire year. However, a nuclear power plant located in the ROI would use cooling water taken from a nearby river or lake, which would have relatively low concentrations of total dissolved solids. In addition, modern cooling towers would be equipped with drift eliminators to minimize the loss of cooling water from the tower via drift. Thus, PM emissions from cooling towers would be anticipated to be minimal. The NRC staff expects similar air emissions for combustion sources from a new nuclear plant as is currently being emitted from Byron:

- sulfur oxides (SO_x) – 0.02 t (0.02 MT) per year,
- nitrogen oxides (NO_x) – 28 t (25 MT) per year,
- carbon monoxide (CO) – 7.5 t (6.8 MT) per year,
- particulate matter ($PM_{2.5}$) – 23 t (21 MT) per year,
- particulate matter (PM_{10}) – 23 t (21 MT) per year, and
- carbon dioxide equivalent (CO_2e) – 1,501 t (1,363 MT) per year.

The NRC staff evaluated potential impacts on air quality associated with criteria pollutants and GHG emissions from operating a new nuclear alternative. The NRC staff determined that the impacts would be minimal. Therefore, the NRC staff concludes that the impacts of operation of a new nuclear alternative on air quality from emissions of criteria pollutants and GHGs would be SMALL.

The NRC staff concludes that the air quality impacts associated with construction and operation of a new nuclear alternative would be SMALL.

4.3.3.2 Noise

Construction of a new nuclear power plant is similar to that of other large industrial projects and involves many noise-generating activities. In general, noise emissions vary with each phase of construction, depending on the level of activity, the mix of construction equipment for each phase, and site-specific conditions. Noise propagation to receptors is affected by several factors, including source-receptor configuration, land cover, meteorological conditions (temperature, relative humidity, and vertical profiles of wind and temperature), and screening (such as topography, and natural or manmade barriers). Typical construction equipment, such as dump trucks, loaders, bulldozers, graders, scrapers, air compressors, generators, and mobile cranes would be used, and pile-driving and blasting activities would take place, during the construction of a new nuclear power plant. Other noise sources include commuter, delivery, and support vehicular traffic traveling within, to, and from the facility.

During the construction phase, a variety of construction equipment would be used and at varying duration. Noise emissions from construction equipment are predicted to be in the 85 to 100 dBA range (Knauer and Pedersen 2011); however, noise levels attenuate rapidly with distance such that at half a mile distance from construction equipment, 85 to 90 dBA noise levels can drop to 51 to 61 dBA (NRC 2002). Additionally, noise abatement and controls can be incorporated to reduce noise impacts. Accounting for attenuation from the construction site and noise controls, predicted noise levels can exceed EPA's guideline of 55 dbA but be less than HUD's acceptable noise level guideline of 65 dBA. Based on the temporary nature of construction activities, consideration of noise attenuation from the construction site to residences, the location and characteristics (i.e., ground cover), and good noise control practices, the NRC staff concludes that the potential noise impacts of construction activities from a new nuclear alternative would be SMALL.

During the operation phase, noise sources from the new nuclear power plant would come from cooling towers, transformers, turbines, pumps, compressors, other auxiliary equipment such as standby generators or auxiliary boilers, and vehicular traffic (commuting, delivery, and support), similar to those for Byron discussed in Section 3.3.3 of this SEIS. Noise level estimates at four receptors around Byron and the nearest residence located more than 0.9 km (0.6 mi) from primary noise sources (see Section 3.3.3 of this SEIS), ranged between 50 and 57 dBA L_{dn}, considering both the background and station contributions.

Although the plant layout and the distance from primary noise sources to the nearby receptors at Byron might be different from those at a new nuclear alternative, the NRC staff does not expect noise impacts for a new nuclear plant to be any greater than that analyzed for the existing Byron site. Therefore, the noise impacts of a new nuclear plant located within the ROI region would be SMALL.

The NRC staff concludes that the noise impacts associated with operation and construction of a new nuclear alternative would be SMALL.

4.3.4 IGCC Alternative

4.3.4.1 Air Quality

This alternative includes the construction and operation of four IGCC units with a total output of 2,472 MWe and a capacity factor of 85 percent. The new power plant is assumed to be located at existing power plant site(s). These sites could be located in Illinois (including the Byron site) or other adjoining states in the ROI (Indiana, Iowa, Michigan, Missouri, Kentucky, and Wisconsin). New infrastructure and infrastructure upgrades would depend on specific site locations.

Construction of an IGCC plant would be similar to that of other large industrial projects and involves many activities similar to those for a new nuclear alternative presented in Section 4.3.3. Construction of an IGCC plant would result in the release of various criteria pollutants (PM, NO_x, CO, and SO_2), VOCs, HAPs, and GHGs from operation of internal combustion engines in construction vehicles, equipment, delivery vehicles, and vehicles used by the commuting construction workforce. In addition, soil disturbance activities such as earthmoving and material handling would generate fugitive dust. The onsite storage and dispensing of vehicle and equipment fuels result in VOC releases. Air emissions would be intermittent and vary based on the level and duration of a specific activity throughout the construction phase. Construction lead times for IGCC plants are estimated to be 3 years (NETL 2013b). Impacts would be localized, intermittent, and short-lived, and adherence to well-developed and well-understood construction BMPs would mitigate such impacts. The NRC staff concludes that construction-related impacts on air quality from an IGCC alternative would be of relatively short duration and would be SMALL.

The sources of air emissions during operation include heat recovery steam generator (HRSG) stacks, the wet gas sulfuric acid (WSA) system exhaust, acid gas removal process startup/shutdown vents, startup stacks, flares, material handling equipment, and mechanical draft cooling towers (DOE 2010a). The HRSG stacks would release the most emissions. Auxiliary boilers and firewater pumps would also generate emissions on an infrequent basis.

Compared to conventional coal-fired power plants, the proposed IGCC power plant would reduce sulfur dioxide, nitrogen oxides, mercury, and PM emissions by removing constituents from the syngas (DOE 2010a). The IGCC alternative would also result in lower nitrogen oxide emissions since nearly 100 percent of the fuel-bound nitrogen from the syngas would be removed from the syngas before combustion in the gas turbine. Sulfur removal technology would remove more than 99 percent of the sulfur in the syngas. The use of sulfide-activated carbon could remove more than 92 percent of mercury from the syngas. More than 99.9 percent of particulate emissions would be removed from the syngas using high-temperature, high-pressure filtration.

Various Federal and state regulations aimed at controlling air pollution would affect an IGCC alternative located in the seven-state ROI. A new IGCC plant would qualify as a new major source because of its potential to emit (PTE) greater than 100 t per year of criteria pollutants, and would be subject to New Source Review (NSR) permitting program requirements under the Clean Air Act (CAA) (EPA 2013d). An NSR permit or construction permit would specify emission limits for each pollutant, along with monitoring and reporting requirements, specifications for fuel and control equipment, and monitoring and performance testing for the IGCC units, auxiliary boiler, and WSA process. The new IGCC plant would be required to secure a Title V operating permit from the state agency.

An NSR review would limit emissions for criteria pollutants and would reflect existing ambient air quality at the selected location. Because the IGCC alternative could be located anywhere within the seven-state ROI, it is unknown at this time whether or not the specific site(s) would be located within a designated attainment area. For instance, if the IGCC alternative were to be located at the Byron site, Ogle County is designated as an attainment/unclassifiable area for all criteria pollutants (40 CFR 81.314). Analysis regarding National Ambient Air Quality Standards (NAAQS) compliance would be conducted at the specific site location. The IGCC alternative also would need to comply with the standard of performance for new stationary sources set forth in 40 CFR Part 60, Subpart Da, “Standards of performance for electric utility steam generating units.”

If the IGCC alternative were located close to a mandatory Class I area, additional air pollution control requirements would be necessary (Subpart P of 40 CFR Part 51) as mandated by the Regional Haze Rule. Within the ROI, there are five Class I Federal areas, including: Mammoth Cave National Park (NP) in Kentucky (40 CFR 81.411), Isle Royale NP and Seney Wilderness Area (WA) in Michigan (40 CFR 81.414), and Hercules-Glades WA and Mingo WA in Missouri (40 CFR 81.416). The rule could apply to the IGCC alternative, but would depend on specific site locations(s). If the IGCC alternative were to be located at the Byron site, the nearest[5] Class I Federal area for visibility protection is the Seney WA in Michigan (40 CFR 81.414), about 520 km (323 mi) north-northeast of the Byron site.

[5] Rainbow Lake in Wisconsin is a Mandatory Federal Class I area where visibility is not an important air quality related value. In 1980 Rainbow Lake was excluded for purposes of visibility protection as a Class I area. Rainbow Lake is approximately 505 km (314 mi) north-northwest of the Byron site.

Air emissions for the IGCC alternative were estimated based on data presented in Table 4.3-1 in the GEIS (NRC 2013a). The resulting IGCC emissions are estimated to be as follows:

- sulfur dioxide (SO_2)—820 t (740 MT) per year,
- nitrogen oxides (NO_x)—3,000 t (2,720 MT) per year,
- particulate matter (PM_{10})—480 t (435 MT) per year,
- carbon monoxide (CO)—2,045 t (1,850 MT) per year, and
- carbon dioxide equivalent (CO_2e)—14.3 million t (13.0 million MT) per year.

The IGCC alternative would produce 820 t (740 MT) per year of sulfur dioxide and 3,000 t (2,072 MT) per year of nitrogen oxides. The IGCC plant would have to comply with Title IV of the CAA (42 USC § 7651) reduction requirements for sulfur oxides and nitrogen oxides, which are the main precursors of acid rain and the major causes of reduced visibility. Title IV establishes maximum sulfur oxide and nitrogen oxide emission rates from the existing plants and a system of sulfur oxide emission allowances that can be used, sold, or saved for future use by the new plants. The new plant would be subjected to the continuous monitoring requirements of sulfur dioxide and nitrogen oxides as specified in 40 CFR Part 75. The Clean Air Interstate Rule [6] (CAIR) requires 27 states (including Indiana, Iowa, Michigan, Missouri, Kentucky, and Wisconsin) to improve air quality requiring power plants to reduce sulfur dioxide and nitrogen oxide emissions (EPA 2014a). A new IGCC plant would be subject to these additional rules and regulations.

The IGCC alternative would emit approximately 14.3 million t (approximately 13 million MT) per year of CO_2e emissions. The plant would be subjected to the continuous monitoring requirements for carbon dioxide, as specified in 40 CFR Part 75. On July 12, 2012, EPA issued a final rule tailoring the criteria that determine which stationary sources and modifications to existing projects become subject to permitting requirements for GHG emissions under the prevention of significant deterioration (PSD) and Title V Federal permit programs of the CAA (77 FR 41051). Beginning January 2, 2011[7], operating permits issued to major sources of GHG under the PSD or Title V permit programs must contain provisions requiring the use of best available control technology (BACT) to limit the emissions of GHGs if those sources would be subject to PSD or Title V permitting requirements because of their non-GHG pollutant emission potentials and their estimated GHG emissions are at least 75,000 tons/yr of CO_2e. If the IGCC alternative meets PSD or Title V permitting requirements for non-GHG pollutant emissions and the GHG emission thresholds established in the rule, then GHG emissions from this alternative would be regulated under the PSD and Title V permit programs.

[6] The Clean Air Interstate Rule (CAIR) was first issued by EPA in 2005; however, the Federal rule was vacated by the D.C. Circuit Court on February 8, 2008. In December 2008, the U.S. Court of Appeals for the D.C. Circuit reinstated the rule, allowing it to remain in effect but also requiring EPA to revise the rule and its implementation plan. On July 6, 2010, EPA proposed replacing CAIR with the Cross-State Air Pollution Rule (CSAPR) for control of sulfur dioxide and nitrogen oxide emissions that cross state lines, the regulations of which would be implemented in 2011 and finalized in 2012. However, CSAPR was vacated by the D.C. Circuit Court on August 21, 2012. On April 29, 2014, the U.S. Supreme Court reversed the D.C. Circuit opinion vacating CSAPR. EPA is reviewing the opinion and CAIR remains in effect.

[7] On June 23, 2014, the U.S. Supreme Court issued a decision that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit, but could continue to require PSD and Title V permits otherwise required based on emissions of conventional pollutants. In July 2014, the EPA issued a memorandum in response to the Supreme Court's decision and acknowledged that while the decision is pending judicial action, the EPA will no longer require PSD or Title V permits for GHG-emitting sources that are not sources subject to PSD or Title V permits based on emissions of conventional pollutants (nitrogen oxides, carbon monoxide, etc.) (EPA 2014b).

In response to the Consolidated Appropriations Act of 2008 (Public Law 110-161), EPA issued final mandatory GHG reporting regulations for major sources effective in December 2009 (EPA 2012b). Major sources are defined as those emitting more than 25,000 t per year of all GHGs. An IGCC alternative would be subject to these reporting regulations with or without carbon capture. On January 8, 2014, EPA issued a new proposal for GHG emissions from new fossil fuel-fired electric utility steam generating units (79 FR 1430). It also proposes standards of performance for IGCC units that burn coal. The performance standards are based on partial implementation of carbon capture and sequestration (CCS) as the best system of emission reduction (BSER). Although the proposed rule has not been finalized, the IGCC alternative analysis includes an option for future implementation of CCS.

An IGCC alternative also would be subject to the Mercury and Air Toxics Standards (MATS) final rule, finalized by EPA on December 16, 2011 (EPA 2012a). Standards for emissions of heavy metals (mercury, arsenic, chromium, and nickel) and acid gases (hydrochloric acid and hydrofluoric acid) are set by MATS. Mercury is the most prominent HAP emitted and is subject to regulation by the MATS rule. New IGCC units are required to meet a mercury emission limit of 0.003 lb per gigawatt-hour (40 CFR Part 63 Subpart UUUUU). NRC staff estimates that an IGCC alternative replacing the electrical output of Byron would generate 0.03 t (0.02 MT) of mercury per year.

The impact from sulfur dioxide and nitrogen oxide emissions would be significant and subject to a Title V permit. GHG emissions also would be noticeable and significant; GHG emissions would be much larger than the threshold in EPA's GHG Tailoring Rule and GHG emissions may be regulated under the PSD and Title V permit programs. that would trigger a regulated NSR. In the near future, carbon dioxide emissions could be reduced considerably if CCS technology were installed. The NRC staff concludes that the air quality impacts associated with operation of an IGCC alternative would be MODERATE.

The NRC staff concludes that the overall air quality impacts associated with construction and operation of an IGCC alternative would be MODERATE.

4.3.4.2 Noise

Construction of an IGCC plant is similar to that of other large industrial projects, and construction-related noise sources would be virtually the same as those for construction of the nuclear alternative. However, the construction period for the IGCC alternative would be shorter and the level of activities scattered over a wide area would be less extensive compared with construction of a nuclear alternative. Consequently, with construction-related noise for the nuclear alternative as a bounding condition, the NRC staff concludes that construction-related noise associated with the IGCC alternative would be SMALL.

Operation of an IGCC plant would introduce mechanical sources of noise that would be audible off site. Continuous sources include the mechanical equipment associated with normal plant operations and mechanical draft cooling towers. Intermittent sources include the equipment related to coal handling, solid waste disposal, transportation related to coal and lime/limestone delivery, use of outside loudspeakers, and the commuting of plant employees. Noise associated with rail delivery of coal and lime/limestone would extend beyond the plant site boundary and would be most significant for residents living in the vicinity of the facility and along the rail route. Noise impacts associated with rail delivery are predicted to be in the 80 to 96 dBA range (NRC 2002). Transportation-related noise sources have the potential to impact as these noise sources reach beyond the plant site boundary. The NRC staff concludes that the potential impacts of noise on residents in the vicinity of the facility of an IGCC alternative and the rail line are considered to range from SMALL to MODERATE, depending on the distance from primary noise sources to nearby sensitive receptors.

The NRC staff concludes that the overall potential impacts of noise associated with construction and operation of the IGCC alternative and the rail line are considered to range from SMALL to MODERATE.

4.3.5 NGCC Alternative

4.3.5.1 Air Quality

This alternative includes the construction and operation of five NGCC 560-MWe units (total 2,800 MWe) and a capacity factor of 85 percent. These sites could be located at an existing power plant site in the ROI (including the Byron site). Some infrastructure upgrades may be required and would require construction of a new or upgraded pipeline. Using existing power plant sites maximizes availability of infrastructure and reduces disruption to land and populations.

Construction of an NGCC power plant would be similar to that of other large industrial projects. Construction of an NGCC power plant would result in the release of various criteria pollutants (PM, NO_x, CO, and SO_2), VOCs, HAPs, and GHGs from the operation of internal combustion engines in construction vehicles, equipment, delivery vehicles, and vehicles used by the commuting construction workforce. In addition, onsite soil disturbance activities such as earthmoving and material handling would generate fugitive dust. Releases of VOCs will also result from the onsite storage and dispensing of vehicle and equipment fuels. Air emissions would be intermittent and vary based on the level and duration of a specific activity throughout the construction phase. Gas-fired power plants are constructed relatively quickly; construction lead times for NGCC plants are around 2 to 3 years (EIA 2011; OECD/NEA 2005). Impacts would be localized, intermittent, and short-lived, and adherence to well-developed and well-understood construction BMPs would mitigate such impacts. Therefore the NRC staff concludes that construction-related impacts on air quality from an NGCC alternative would be of relatively short duration and would be SMALL.

Operation of the NGCC plant would result in significant emissions of certain criteria pollutants, including carbon monoxide, nitrogen oxides, and PM. The sources of air emissions during operation include gas turbines through HRSG stacks and mechanical draft cooling towers. Auxiliary boilers and emergency generators would also generate emissions on an infrequent basis.

The NGCC alternative could be located anywhere within the seven-state ROI; it is therefore unknown at this time whether or not the specific site(s) would be located within a designated attainment area. For instance, if the NGCC alternative were to be located at the Byron site, Ogle County is designated as an attainment/unclassifiable area for all criteria pollutants (40 CFR 81.314). Analysis regarding NAAQS compliance would be conducted at the specific site location. Various Federal and state regulations aimed at controlling air pollution would affect an NGCC alternative located in the seven-state ROI. An NGCC plant would be subject to NSR permitting program requirements to ensure air emissions are minimized and the local air quality is not substantially degraded (EPA 2013d). The new NGCC plant would be required to secure a Title V operating permit from the state agency. The NGCC plant would need to comply with the standards of performance for stationary combustion turbines set forth in 40 CFR Part 60 Subpart KKKK. If the NGCC alternative were located close to a mandatory Class I area, additional air pollution control requirements would be required (Subpart P of 40 CFR Part 51) as mandated by the Regional Haze Rule. A detailed discussion of these Federal and state regulations is provided in Section 4.3.4.1 (see Air Quality Operation discussion for the IGCC alternative).

Air emissions for the NGCC alternative were estimated based on data presented in Table 4.3-2 in the GEIS (NRC 2013a) and EPA emission factors (EPA 2000; NRC 2013a). The estimate is based on using advanced F class gas turbines at one or multiple sites within the ROI. The resulting NGCC emissions are estimated to be as follows:

- sulfur dioxide (SO_2)—380 t (350 MT) per year,
- nitrogen oxides (NO_x)—600 t (540 MT) per year,
- particulate matter (PM_{10})—210 t (190 MT) per year,
- carbon monoxide (CO)—1,690 t (1,530 MT) per year, and
- carbon dioxide equivalent (CO_2e)—7.9 million t (7.2 million MT) per year.

The NGCC alternative would produce 380 t (350 MT) per year of sulfur dioxide and 600 t (540 MT) per year of nitrogen oxides based on the use of dry low-nitrogen-oxide combustion technology coupled with use of selective catalytic reduction (SCR) to significantly reduce nitrogen oxide emissions (NETL 2013b). The new plant would be subjected to the continuous monitoring requirements of sulfur dioxide and nitrogen oxides as specified in 40 CFR Part 75. The CAIR requires 27 states (including Indiana, Iowa, Michigan, Missouri, Kentucky, and Wisconsin) to improve air quality, requiring power plants to reduce sulfur dioxide and nitrogen oxide emissions (EPA 2014a). A new NGCC plant would be subject to these additional rules and regulations.

The NGCC alternative would emit approximately 7.9 million t (approximately 7.2 million MT) per year of CO_2e. The plant would be subjected to the continuous monitoring requirements for carbon dioxide, as specified in 40 CFR Part 75. On July 12, 2012, EPA issued a final rule tailoring the criteria that determine which stationary sources and modifications to existing projects become subject to permitting requirements for GHG emissions under the PSD and Title V Programs of the CAA (77 FR 41051). Beginning January 2, 2011[8], operating permits issued to major sources of GHG under PSD or Title V Federal permit programs must contain provisions requiring the use of best available control technology (BACT) to limit the emissions of GHGs if those sources would be subject to PSD or Title V permitting requirements because of their non-GHG pollutant emission potentials and their estimated GHG emissions are at least 75,000 tons/yr of CO_2 equivalents (CO_2e). If the NGCC alternative meets PSD or Title V permitting requirements for non-GHG pollutant emissions and the GHG emission thresholds established in the rule, then GHG emissions from this alternative would be regulated under the PSD and Title V permit programs.

In response to the Consolidated Appropriations Act of 2008 (Public Law 110-161), EPA issued final mandatory GHG reporting regulations for major sources effective in December 2009 (EPA 2012b). Major sources are defined as those emitting more than 25,000 t per year of all GHGs. An NGCC alternative would be subject to these reporting regulations with or without carbon capture.

[8] On June 23, 2014, the U.S. Supreme Court issued a decision that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit, but could continue to require PSD and Title V permits otherwise required based on emissions of conventional pollutants. In July 2014, the EPA issued a memorandum in response to the Supreme Court's decision and acknowledged that while the decision is pending judicial action, the EPA will no longer require PSD or Title V permits for GHG-emitting sources that are not sources subject to PSD or Title V permits based on emissions of conventional pollutants (nitrogen oxides, carbon monoxide, etc.) (EPA 2014b).

On January 8, 2014, EPA issued a new proposal for GHG emissions from new fossil fuel-fired electric utility steam generating units (79 FR 1430). It also proposes standards of performance for natural gas-fired stationary combustion turbines based on modern, efficient NGCC technology as the BSER.

In December 2000, EPA issued regulatory findings on emissions of HAPs from electric utility steam-generating units (65 FR 79825). These findings indicated that natural gas-fired plants emit HAPs such as arsenic, formaldehyde, and nickel and stated that:

> …the impacts due to HAP emissions from natural gas-fired electric utility steam generating units were negligible based on the results of the study. The Administrator finds that regulation of HAP emissions from natural gas-fired electric utility steam generating units is not appropriate or necessary. [65 FR 79825]

Mercury is not emitted from NGCC power plants due to the lack of mercury in natural gas used as fuel.

Considerable air emissions are emitted from operations of the NGCC alternative. The impacts from nitrogen oxide emissions would be significant and subject to a Title V permit. GHG emissions also would be noticeable and significant; carbon dioxide emissions would be much larger than the threshold in EPA's GHG Tailoring Rule. The NRC staff concludes that the overall air quality impacts associated with operation of an NGCC alternative would be MODERATE.

The NRC staff concludes that the overall air quality impacts associated with construction and operation of an NGCC alternative would be MODERATE.

4.3.5.2 Noise

The construction-related noise sources for an NGCC alternative would be virtually the same as those for construction of the IGCC alternative. Construction vehicles and equipment associated with the construction of the NGCC plant would generate noise; these impacts would be intermittent and last only through the duration of plant construction. Noise emissions from common construction equipment would be in the 85 to 100 dBA range (Knauer and Pedersen 2011). However, noise abatement and controls can be incorporated to reduce noise impacts. The review team concludes that construction-related noise impacts associated with the NGCC alternative would be SMALL.

Noise impacts from operations would include cooling towers (water pumps, cascading water, or fans), transformers, turbines, pumps, compressors, exhaust stacks, the combustion inlet filter house, condenser fans, high-pressure steam piping, and vehicles (Saussus 2012). Pipelines delivering natural gas fuel could be audible off site near gas compressor stations, but such noise impacts would be similar to impacts already occurring in the vicinity of the existing pipeline to which the new NGCC site would connect. Most noise-producing equipment is located inside the power block buildings and no outside fuel-handling activities will occur. Minor offsite noise sources could include pipeline compressor stations. The NRC staff concludes that operation-related noise impacts from the NGCC alternative would be SMALL.

The NRC staff concludes that construction operation-related noise impacts from the NGCC alternative would be SMALL.

4.3.6 Combination Alternative (NGCC, Wind, Solar)

The combination alternative relies on NGCC, wind, and solar generating capacity. The total installed solar photovoltaic (PV) capacity is 1,193 megawatts (MW), the total installed wind capacity is 6,042 MW of onshore wind, and the total installed capacity for NGCC is 267 MW in this alternative. All portions of the combination alternative would be located in Illinois or other adjoining states in the ROI (Indiana, Iowa, Michigan, Missouri, Kentucky, and Wisconsin).

The NGCC alternative would require one 267-MW unit. For the NGCC portion of the combination alternative, it is assumed that sites would be located at an existing power plant site which maximizes availability of existing infrastructure and reduces disruption to land and populations. Most of the wind farms would likely be located on open agricultural cropland, which would remain largely unaffected by the wind turbines. The solar portion requires 1,193 MW, and it is assumed that some of the capacity would be from small units and may be installed on building roofs or on existing residential, commercial, or industrial sites.

4.3.6.1 Air Quality

Air emissions associated with the construction of the NGCC portion of the combination alternative are similar to the NGCC alternative but reduced considerably because its electricity output is approximately 10 percent that of the NGCC alternative. As discussed in Section 4.3.5.1, construction activities for an NGCC alternative would cause some temporary impacts to air quality from dust generation during operation of the earthmoving and material handling equipment and exhaust emissions from worker vehicles and construction equipment. These emissions include criteria pollutants, VOCs, GHGs, and small amounts of HAPs. However, these impacts would be localized, intermittent, and short-lived, and adherence to well-developed and well-understood construction BMPs would mitigate such impacts. The NRC staff concludes that construction-related impacts on air quality from an NGCC portion of the combination alternative would be of relatively short duration and would be SMALL.

For the wind portion of the combination alternative, only a small percentage of site land (5 percent or less) would be disturbed by construction activities because wind turbines need to be separated from one another in order to maximize energy production and avoid wake turbulences created by upwind turbines. Construction of the wind portion of the combination alternative would involve a number of activities, including road and staging/laydown area construction, land clearing, topsoil stripping, earthmoving operations, grading, ground excavation, drilling, foundation treatment, wind turbines erection, ancillary building/structure construction, and electrical and mechanical installation. For most wind energy facilities, the site preparation phase would last for only a few months, followed by a year-long construction phase (depending on size of the wind energy facility) (Tegen 2006). Air emissions associated with construction activities result from fugitive dust from soil disturbances and engine exhaust from heavy equipment and vehicular traffic. These emissions include criteria pollutants, VOCs, GHGs, and HAPs. Dust suppression methods and other mitigation measures could reduce impacts from fugitive dust. The wind portion of the combination alternative would have no power block, for which intensive construction activities would occur. Accordingly, the number of heavy equipment and workforce, level of activities, and construction duration would be substantially lower than other alternatives. Therefore, the NRC staff concludes that the overall air quality impacts associated with construction of the wind portion of the combination alternative would be SMALL.

Construction of the solar portion of the combination alternative would cause temporary impacts to air quality from fugitive dust from soil disturbances and engine exhaust from heavy equipment and from vehicular traffic. Air emissions associated with construction activities include criteria pollutants, VOCs, GHGs, and HAPs to a lesser amount. Dust suppression methods and other mitigation measures could reduce impacts from fugitive dust. The solar PV portion of the combination alternative would have no power block, for which intensive construction activities would occur. Accordingly, the number of heavy equipment and workforce, level of activities, and construction duration would be substantially lower than those for other alternatives. Therefore, the NRC staff concludes that the overall air quality impacts associated with construction of the solar PV portion of the combination alternative would be SMALL.

Air emissions associated with the operation of the NGCC portion of the combination alternative are similar to the NGCC alternative in Section 4.3.5.1 but reduced proportionally because its electricity output is approximately 13 percent that of the NGCC alternative.

Air emissions for the NGCC alternative were estimated based on data presented in Table 4.3-2 in the GEIS (NRC 2013a) and Energy Information Administration (EIA) emission factors (EIA 1999; NRC 2013a). The estimate is based on using advanced F class gas turbines at one or multiple sites within the ROI. The resulting NGCC emissions are estimated to be as follows:

- sulfur dioxide (SO_2)—50 t (45 MT) per year,
- nitrogen oxides (NO_x)—80 t (70 MT) per year,
- particulate matter (PM_{10})—30 t (25 MT) per year,
- carbon monoxide (CO)—220 t (200 MT) per year, and
- carbon dioxide equivalent (CO_2e)—1.0 million t (0.9 million MT) per year.

Annual emissions of sulfur dioxide and nitrogen oxides would be lower than the major source threshold, while those of carbon monoxide would exceed the major source threshold. The overall air quality impacts associated with operation of the NGCC portion of the combination alternative would be SMALL to MODERATE.

Emissions from the operation of wind energy facilities would include minor dust and engine exhaust emissions from vehicles and heavy equipment associated with site inspections, maintenance activities, and wind erosion from cleared land and access roads. The types of emission sources and pollutants during operation would be similar to those during construction, but much fewer emissions would be released during operation. The NRC staff concludes that the overall air quality impacts associated with the operation of the wind portion of the combination alternative would be SMALL.

In general, air emissions associated with the operation of solar energy facilities are negligible because no fossil fuels are burned to generate electricity. Emissions from solar fields would include fugitive dust and engine exhaust emissions from vehicles and heavy equipment associated with site inspections, maintenance activities (panel washing or replacement), and wind erosion from cleared lands and access roads. The types of emission sources and pollutants during operation would be similar to those during construction, but much fewer emissions would be released during operation. These emissions should not cause exceedances of air quality standards or have any impacts on climate change. The NRC staff concludes that the overall air quality impacts associated with the operation of the solar PV portion of the combination alternative would be SMALL.

The overall air quality impacts associated with construction and operation of the combination alternative would be SMALL to MODERATE.

4.3.6.2 Noise

The construction-related noise sources for the NGCC portion of the combination alternative would be virtually the same as those for construction of the NGCC alternative. The construction period for the NGCC portion would be shorter and the level of construction activities would be less extensive than the NGCC alternative. Consequently, the NRC staff concludes that construction-related noise associated with the NGCC portion of the combination alternative would be SMALL.

Construction of the wind portion of the combination alternative would involve a number of activities, as described above. The wind portion of the combination alternative would have no power block, for which intensive construction activities would occur. Accordingly, the number of heavy equipment and workforce, level of activities, and construction duration would be substantially lower than other alternatives. Considering these factors, the NRC staff concludes that construction-related noise associated with the wind portion of the combination alternative would be SMALL.

Construction of the solar PV portion of the combination alternative would involve a number of activities. The solar PV portion of the combination alternative would have no power block, for which intensive construction activities would occur. Accordingly, the number of heavy equipment and workforce, level of activities, and construction duration would be substantially lower than other alternatives. Considering these factors, the NRC staff concludes that construction-related noise associated with the solar PV portion of combination alternative would be SMALL.

Besides noise from the power block area, cooling towers, and vehicular traffic, operation-related noise for the NGCC portion would include limited outdoor waste handling activities. Pipelines delivering natural gas fuel could be audible off site near gas compressor stations, but such sound impacts would be similar to impacts already occurring in the vicinity of the existing pipeline to which the new NGCC site would connect. Most noise-producing equipment is located inside the power block buildings, and no outside fuel-handling activities would occur. Minor offsite noise sources could be pipeline compressor stations. The NRC staff concludes that operation-related noise from the NGCC portion of the combination alternative would be SMALL.

Noise impacts from wind generation operations would include aerodynamic noise from the turbine rotors and mechanical noise from the turbine drivetrain components. Noise levels are dependent on the wind and atmospheric conditions, which vary with time, and on site-specific conditions, including: the number and size of wind turbines, their layout, distance to nearby sensitive receptors, land cover, and topography. Wind turbine noise levels can reach 105 dBA; however, studies show that at approximately 1,000 ft (300 m) from a wind turbine, noise levels can reach 43 dBA (GE 2010; Hessler 2011). Therefore, masking effects of background noise should be taken into consideration. Unless noise from wind turbines is masked by high background levels (e.g., near major highways or industrial complexes), it can be noticeable and annoying at farther distances. One study indicated that, for the same A-weighted sound level, proportions of respondents annoyed by wind turbine noise are higher than for other community noise, such as aircraft, road, or railway traffic, and that the proportion annoyed increases more rapidly (Pedersen and Persson Waye 2004). Therefore, the NRC staff concludes that operation-related noise from the wind portion of the combination alternative would be SMALL to MODERATE, depending on the layout and location of the wind facility and the distance to nearby sensitive receptors.

The solar PV portion of the combination alternative would have no power block and cooling towers, and thus there would be a minimal number of noise sources with low-level noises. Noise sources include small-scale cooling systems to dissipate heat from solar module assemblies, solar tracking devices, inverters, transformers, and vehicle traffic for maintenance and inspection. Because of minimal noise-generating activities, noise from a solar PV facility would be anticipated to be inaudible or barely perceptible at the facility boundaries. Considering the minimum number of sources with low-noise levels and the area size of the solar PV facility, the NRC staff concludes that operation-related noise from the solar PV portion of the combination alternative would be SMALL.

The noise impacts associated with construction and operation of the combination alternative would be SMALL to MODERATE.

4.3.7 Purchased Power

4.3.7.1 Air Quality

As discussed in Section 2.2.2.5, purchased power would come from common types of existing technology (coal, natural gas, and nuclear) within the ROI, and it is not likely that new facilities would be constructed to replace Byron. Construction of new transmission lines would result in additional amounts of air emissions. Air emissions associated with the construction of transmission lines would be from operation of the earthmoving and material handling equipment and exhaust emissions from worker vehicles and construction equipment. These emissions include criteria pollutants, VOCs, GHGs, and HAPs. However, these impacts would be temporary and not likely to be high. For purchased power from existing plants, the impacts on air quality are expected to be SMALL as there would be minimal change in existing plant operations.

If new facilities were to be constructed for purchased power, the impact on air quality would depend on the plant technology constructed, since air emissions can vary substantially, as can be observed from the alternative air quality discussions provided above. For instance, natural gas- and coal-fired plants emit higher amounts of nitrogen oxides, sulfur oxides, PM, and carbon dioxide than nuclear plants. Purchased power from new nuclear plants would not have noticeable impacts on air quality. New natural gas- and coal-fired plants would have noticeable impacts on air quality as a result of the higher amounts of air emissions.

Therefore, impacts on air quality from purchased power of new plants would be SMALL to MODERATE.

4.3.7.2 Noise

Purchased power from existing electricity generating facilities would not have noticeable impacts on noise as there would be minimal change in existing plant operations. Purchased power from new generating facilities could have impacts on noise. Construction and operation of new facilities could result in additional noise sources including mechanical equipment associated with normal plant operations and vehicular traffic. Additionally, construction of new transmission lines could increase noise levels. Increase in noise levels from construction of new transmission lines and new facilities would be dependent on the distance of residents to the noise sources. Noise levels from operation will also be dependent on the type of technology, for instance, operation of nuclear or wind power. Therefore, impacts from purchased power on noise would be SMALL to MODERATE.

4.3.8 Conclusions

<u>Air Quality</u>

Estimated air emissions from operations of the proposed action and five alternatives are presented in Table 4–3. Air emissions from the proposed action and the new nuclear alternative would be lowest, while the IGCC alternative would release the highest emissions, followed by the NGCC alternative. Air emissions from the combination alternative would fall between the nuclear alternative and the NGCC alternative. It is apparent that the IGCC and NGCC alternatives will produce significantly greater air pollutant emissions than those associated with the proposed action (license renewal of Byron), new nuclear alternative, or the combination alternative. Air emissions from purchased power will vary and depend on the type of technology and whether the purchased power is from existing or new constructed technology. If purchased power is solely from coal-fired plants, air emissions would be higher as opposed to purchased power from nuclear plants, which would result in lower emissions. It is assumed that purchased power would come from a combination of technologies. In 2012, coal, natural gas, and nuclear power accounted for 37-, 30-, and 19-percent share, respectively, of total U.S. electricity generation (EIA 2014). Using these percent shares for the purchased power alternative, the NRC staff estimates that air emissions will be greater than the NGCC alternative, but less than the IGCC alternative. However, actual emissions may be greater or less than what is estimated in Table 4–3 and will depend on the technology from which the purchased power comes.

Table 4–3. Estimated Direct Air Emissions From Operation of the Byron Proposed Action and Alternatives (Tons/Year)

	Proposed Action [a]	New Nuclear [b]	IGCC	NGCC	Combination [c]	Purchased Power [d]
NO_x	28	28	3,000	600	80	1,295
SO_x	0.02	0.02	820	380	50	417
PM_{10}	23	23	480	210	30	188
CO	7.5	7.5	2,045	1,690	220	1,265
CO_2e	1.5×10^3	1.5×10^3	14.3×10^6	7.9×10^6	1.0×10^6	7.7×10^6

[a] Highest annual emissions from the Byron Station during the 2008 to 2012 period.

[b] Assumed air emissions from the Byron Station.

[c] Assumed air emissions only from the NGCC portion of the combination alternative.

[d] Assumed air emissions were estimated by assuming that purchased power coal accounted for a 37% share, natural gas a 30% share, nuclear a 19% share, and renewable a 14% share of electricity generation.

Legend: CO = carbon monoxide; CO_2e = carbon dioxide equivalent; PM_{10} = particulate matter, ≤10 μm; NO_x = nitrogen oxides; SO_x = sulfur oxides

<u>Noise</u>

As discussed in the sections above, noise levels and impacts from operation of the NGCC and new nuclear combination alternatives would not be greater than those associated with operation of the Byron site and expected to be SMALL. Noise levels and impacts from operation of the IGCC, combination, and purchased power are expected to be SMALL to MODERATE. Noise levels for these three alternatives are dependent on the distance of receptors to the noise sources unique to the technology. For instance, the IGCC alternative will introduce noise associated with rail delivery predicted to be in the 80 to 96 dBA range. The wind power portion of the combination alternative will introduce wind turbine noise levels that can reach 105 dBA.

4.4 Geologic Environment

This section describes the potential impacts of the proposed action (license renewal) and alternatives to the proposed action on geologic and soil resources.

During construction, for all the alternatives to the proposed action discussed in this section, sources of aggregate such as crushed stone and sand and gravel would be required to construct buildings, foundations, roads, and parking lots. These resources would likely be obtained from commercial suppliers using local or regional sources. In addition, land would be cleared of vegetation. Land clearing during construction and the installation of power plant structures and impervious surfaces would expose soils to erosion and alter surface drainage. To reduce soil erosion, BMPs would be implemented in accordance with applicable permitting requirements. These practices would include use of sediment fencing, staked hay bales, check dams, sediment ponds, riprap aprons at construction and laydown yard entrances, mulching and geotextile matting of disturbed areas, and rapid reseeding of temporarily disturbed areas. Removed soils and any excavated materials would be stored on site for redistribution, such as for backfill at the end of construction. Therefore, for all the alternatives to the proposed action, construction impacts on geologic and soil resources would be SMALL.

Table 4–4 identifies issues related to geology and soils that are applicable to the Byron Station during the renewal term. Section 3.4 describes the local and regional geologic environment of the Byron site.

Table 4–4. Geology and Soils Issues

Issue	GEIS Section	Category
Geology and soils	4.4.1	1

Source: Table B-1 in Appendix B, Subpart A, to 10 CFR Part 51

4.4.1 Proposed Action

As further discussed below, the impact by the proposed action on geology and soil resources are SMALL.

The NRC staff did not identify any new and significant information associated with the Category 1 geology and soils issues identified in Table 4–4 during the review of the applicant's ER (Exelon 2013a), the site audit, the scoping process, or the evaluation of other available information. As a result, no information or impacts related to these issues were identified that would change the conclusions presented in the GEIS (NRC 1996, 2013a). For these geology and soils issues, the GEIS concludes that the impacts are SMALL. Therefore, it is expected that there would be no incremental impacts related to these Category 1 issues during the renewal term beyond those discussed in the GEIS, and therefore the impacts associated with these issues by the proposed action would be SMALL.

4.4.2 No-Action Alternative

There would not be any impacts to the geology and soils at the Byron site with shutdown of the facility. Therefore, impacts would be SMALL.

4.4.3 New Nuclear Alternative

This alternative would be located at an existing plant site or retired coal plant site. As such, it would be located in an area where the soils had already been disturbed by previous activities at the site. For this alternative, the impacts on the geology and soil resources would occur during construction. As discussed in Section 4.4 of the GEIS (NRC 2013a), construction impacts for all alternatives to the proposed actions would be SMALL, and therefore the impact of this alternative on geology and soil resources would be SMALL.

4.4.4 IGCC Alternative

This alternative would be located at an existing plant site. As such, it would be located in an area where the soils had already been disturbed by previous activities at the site. For this alternative, the impacts on the geology and soil resources would occur during construction. As discussed in Section 4.4 of the GEIS (NRC 2013a), construction impacts for all alternatives to the proposed actions would be SMALL, and therefore the impact of this alternative on geology and soil resources would be SMALL.

4.4.5 NGCC Alternative

This alternative would be located at an existing plant site or retired coal plant site. As such, it would be located in an area where the soils had already been disturbed by previous activities at the site. For this alternative, the impacts on the geology and soil resources would occur during construction. As discussed in Section 4.4 of the GEIS (NRC 2013a), construction impacts for all alternatives to the proposed actions would be SMALL, and therefore the impact of this alternative on geology and soil resources would be SMALL.

4.4.6 Combination Alternative (NGCC, Wind, Solar)

This alternative requires a large amount of land (up to 19,790 ac (8,009 ha)). However, much of the land would be undisturbed. For this alternative, the impacts on the geology and soil resources would occur during construction. As discussed in Section 4.4 of the GEIS (NRC 2013a), construction impacts for all alternatives to the proposed actions would be SMALL, and therefore the impact of this alternative on geology and soil resources would be SMALL.

4.4.7 Purchased Power

The impacts of this alternative on the geology and soil resources are likely to be bounded by the impact descriptions of the other alternatives, and therefore the impact of this alternative on geology and soil resources would be SMALL.

4.5 Water Resources

This section describes the potential impacts of the proposed action (license renewal) and alternatives to the proposed action on surface water and groundwater resources.

4.5.1 Proposed Action

4.5.1.1 Surface Water Resources

The Category 1 (generic) and Category 2 surface water use and quality issues applicable to Byron are discussed in the following sections and listed in Table 4–5. Surface water resource-related aspects and conditions relevant to the Byron site are described in Section 3.5.1.

Table 4–5. Surface Water Resources Issues

Issue	GEIS Section	Category
Surface water use and quality (non-cooling system impacts)	4.5.1.1	1
Altered current patters at intake and discharge structures	4.5.1.1	1
Scouring caused by discharged cooling water	4.5.1.1	1
Discharge of metals in cooling system effluents	4.5.1.1	1
Discharge of biocides, sanitary wastes, and minor chemical spills	4.5.1.1	1
Surface water use conflicts (plants with cooling ponds or cooling towers using makeup water from a river)	4.5.1.1	2
Effects of dredging on surface water quality	4.5.1.1	1
Temperature effects on sediment transport capacity	4.5.1.1	1

Sources: Table B-1 in Appendix B, Subpart A, to 10 CFR Part 51; NRC 2013a

Generic Surface Water Resources

The NRC staff did not identify any new and significant information associated with the Category 1 surface water issues identified in Table 4–5 during the review of the applicant's ER (Exelon 2013a), the site audit, the scoping process, or the evaluation of other available information. As a result, no information or impacts related to these issues were identified that would change the conclusions presented in the GEIS (NRC 2013a). For these issues the GEIS concludes that the impacts are SMALL. Therefore, it is expected that there would be no incremental impacts related to these Category 1 issues during the renewal term beyond those discussed in the GEIS, and therefore the impacts associated with these issues by the proposed action would be SMALL.

The Category 2 (Table 4–5) issue related to surface water during the renewal term is discussed in the following text.

Surface Water Use Conflicts

This section presents the NRC staff's review of the plant-specific (Category 2) surface water use conflict issue listed in Table 4–5.

Plants with Cooling Ponds or Cooling Towers Using Makeup Water From a River

For nuclear power plants using cooling towers or cooling ponds supplied with makeup water from a river, the potential impact on the flow of the river and its availability to meet the demands of other users is a Category 2 issue. This designation requires a plant-specific assessment.

In evaluating the potential impacts resulting from surface water use conflicts associated with license renewal, the NRC staff uses as its baseline the surface water resource conditions as described in Sections 3.1.3 and 3.5.1. These baseline conditions encompass the defined hydrologic (flow) regime of the surface water(s) potentially affected by continued operations as well as the magnitude of surface water withdrawals for cooling and other purposes (as compared to relevant appropriation and permitting standards). The baseline also considers other downstream uses and users of surface water.

The mean annual discharge of the Rock River (see Section 3.5.1.1) measured at the U.S. Geological Survey (USGS) gage at Como, Illinois, is 6,033 cubic feet per second (cfs)

(170 cubic meters per second (m^3/s)). As described in Section 3.5.1.2, Byron's average surface water withdrawal rate from the Rock River is 83.2 cfs (2.35 m^3/s or 53.8 mgd), with consumptive use averaging 52.9 cfs (1.5 m^3/s or 34.2 mgd). This results in a rate of consumption of 0.9 percent of the Rock River's average flow. Further, the lowest annual mean flow recorded for the Rock River at Como, Illinois, is 2,187 cfs (61.9 m^3/s), and the mean 90 percent-exceedance flow is 1,760 cfs (49.7 m^3/s) for the period of record. Compared to these measures of reduced river flow, Byron's consumptive water use represents a 2.4- and a 3.0-percent reduction, respectively, in the flow of the Rock River downstream of Byron Station.

In addition, the provisions of Exelon's agreement with the State pursuant to Byron's construction permit for its cooling water intake limit the plant's consumptive use of surface water to no more than 9 percent of total river flow when river flow is at or below 679 cfs (19.1 m^3/s). This condition would represent a consumptive use totaling about 61 cfs (1.7 m^3/s) for Byron operations (see Section 3.5.1.2). Under low river flow conditions, a plant operating procedure stipulates actions that Exelon personnel must take to maintain compliance including reducing circulating water makeup and blowdown flows and, if necessary, reducing reactor power output to reduce consumptive water use.

The construction permit also limits Byron's maximum makeup withdrawal rate from the river to 125 cfs (3.5 m^3/s). However, the maximum (nominal) surface water withdrawal rate for Byron is about 101 cfs (2.85 m^3/s), and, as a result, the maximum permitted withdrawal rate would not likely be exceeded during the period of continued operations.

Future Rock River flow is not expected to significantly change over the license renewal period (Dziegielewski et al. 2005; Exelon 2013a). Future water demand (both groundwater and surface water) in the Illinois counties within the Rock River basin is projected to increase by about 10 percent from 2000 to 2025. Most of this projected demand is for thermoelectric generation near the southern end of the river in the County of Rock Island (Dziegielewski et al. 2005; IEPA 2006).

In conclusion, operation of Byron during the license renewal term is not expected to result in a water use conflict on the Rock River. Byron's surface water withdrawals and low rate of consumptive use of Rock River flow is very unlikely to impact the downstream availability and instream uses of surface water. Byron's surface water withdrawals are also subject to low-flow limitations imposed by the State of Illinois. Therefore, the NRC staff concludes that the potential impacts on surface water resources and downstream water availability from Byron's consumptive water use during the license renewal term would be SMALL.

4.5.1.2 Groundwater Resources

Table 4–6 identifies issues related to groundwater that are applicable to Byron Station during the renewal term. Section 3.5.2 describes groundwater resources at the Byron Station.

The NRC staff did not identify any new and significant information associated with the Category 1 groundwater issues identified in Table 4–6 during the review of the applicant's ER, the site audit, the scoping process, or the evaluation of other available information. As a result, no information or impacts related to these issues were identified that would change the conclusions presented in the GEIS (NRC 2013a). For these issues, the GEIS concludes that the impacts are SMALL. Therefore, it is expected that there would be no incremental impacts related to these Category 1 issues during the renewal term beyond those discussed in the GEIS, and therefore the impacts associated with these issues by the proposed action would be SMALL.

Table 4–6. Groundwater Issues

Issue	GEIS Section	Category
Groundwater contamination and use (noncooling system impacts)	4.5.1.2	1
Groundwater use conflicts (plants that withdraw less than 100 gpm)	4.5.1.2	1
Groundwater use conflicts (plants with closed-cycle cooling systems that withdraw makeup water from a river)	4.5.1.2	2
Radionuclides released to groundwater	4.5.1.2	2

Source: Table B-1 in Appendix B, Subpart A to 10 CFR Part 51

The Category 2 issues related to groundwater during the renewal term are discussed in the following text (see also Table 4–6).

Groundwater Use Conflicts (Plants Using Cooling Towers or Cooling Ponds and Withdrawing Makeup Water From a Small River)

The issue of groundwater use conflicts applies to the Byron Station because it uses cooling towers and withdraws water from a small river. Cooling towers lose water to the atmosphere by evaporation and drift. As a result, less water is returned to Rock River than is withdrawn. This issue evaluates the impact of consuming river water and its impact on groundwater supplies.

The Rock River Alluvium is hydrologically connected to both the Galena-Platteville Dolomite Aquifer and the St. Peter Sandstone Aquifer. Groundwater from these aquifers discharges into the river alluvium. As described in Section 4.5.1.1, the low impact of plant water consumption on Rock River flows over the period of licensing, and therefore on river water levels, means that local aquifers in the site area are very unlikely to suffer dewatering from the consumptive use of river water by the Byron plant. Therefore, the NRC staff concludes that impacts to groundwater use would be SMALL.

Radionuclides Released to Groundwater

As described in Section 3.5.2.3, Exelon discovered in 2006 that water had leaked from some of the vacuum breaker vaults located along the blowdown pipeline running from the plant to the Rock River. The leaked water contaminated a small area of the Galena-Platteville Dolomite aquifer near a few vacuum breaker vaults with low levels of tritium. Other than tritium, no radionuclides above their lower limit of laboratory detection were or have since been discovered from these leaks. Tritium concentrations in the area of contamination were and are well below the EPA drinking water standard of 20,000 picocuries per liter. Exelon has improved monitoring along the pipeline and taken additional measures to prevent future groundwater contamination from the discharge pipeline.

Probably as a result of dilution from local recharge to the aquifer and from dispersion, from 2007 to 2013, tritium concentrations in the areas of groundwater contamination have steadily decreased. There are no wells between the area of contamination and the river (in the direction of groundwater flow); therefore, it is not anticipated that tritium-contaminated groundwater would be intercepted by a private well user. Any tritium in the groundwater that reached the Rock River would be greatly reduced in concentration by the relatively large volumes of water flowing in the river.

Remediation of the contaminated groundwater at Byron Station is not planned by Exelon, because of its low tritium concentrations, limited extent of the contamination, and because the problems causing the leaks from the vacuum breakers along the pipeline have been corrected. The NRC staff will continue to monitor any unanticipated radionuclide releases and take appropriate regulatory action, as warranted. Final cleanup of the site, including contaminated geologic materials, would be addressed by Exelon with NRC oversight during decommissioning of the facility.

Based on its review, the NRC staff concludes that inadvertent releases of tritium have not substantially impaired site groundwater quality and future groundwater quality impacts are not anticipated. The NRC staff therefore concludes that groundwater quality impacts from "radionuclides released to groundwater" are SMALL.

4.5.2 No-Action Alternative

4.5.2.1 Surface Water Resources

The rate of consumptive use of surface water would greatly decrease and eventually cease after Byron is shut down. Wastewater discharges would be reduced considerably. Shutdown would reduce the impacts on surface water use and quality. Therefore, the impact of this alternative on surface water resources would be SMALL.

4.5.2.2 Groundwater Resources

With the cessation of operations at the Byron site, the consumption of groundwater would be much less and there should be little or no impacts on groundwater quality. Therefore, the impact of this alternative on groundwater resources would be SMALL.

4.5.3 New Nuclear Alternative

4.5.3.1 Surface Water Resources

Impacts from construction activities on surface water resources associated with the new nuclear alternative would be considerable in scale by virtue of the land area required for new nuclear units (i.e., 355 ac (143 ha)). Deep excavation work for the nuclear island as well as extensive site clearing and a large laydown area for facility construction would have the potential for direct and indirect impacts on water resources.

Construction activities would alter any onsite surface water drainage features. Some temporary impacts to surface water quality may result from increased sediment loading and from any pollutants in stormwater runoff from disturbed areas, from excavation, and any dredge-and-fill activities. Stormwater runoff from construction areas and spills and leaks from construction equipment could potentially affect downstream surface water quality. Nevertheless, application of BMPs in accordance with a State-issued National Pollutant Discharge Elimination System (NPDES) general permit, including appropriate waste management, water discharge, stormwater pollution prevention, and spill prevention practices, would prevent or minimize any surface water quality or groundwater quality impacts during construction.

In addition, the NRC staff assumes that any existing intake and discharge infrastructure at an alternative site location would be refurbished and used to maximize use of existing facilities. This would reduce construction-related impacts on surface water quality. Dredge-and-fill operations would be conducted under a permit from the U.S. Army Corps of Engineers (USACE) and State-equivalent permits requiring the implementation of applicable BMPs to minimize associated impacts.

The staff assumes that there would be no direct use of surface water during construction because it is expected that groundwater would be used or water could be supplied by a local water utility or trucked to the point of use. During construction, the dewatering of excavations would not be expected to affect offsite surface water bodies.

The operation of the two new nuclear units would require an estimated 83.5 cfs (2.4 m^3/s or 54 million gallons per day (mgd)) of surface water for cooling makeup and related processes. Consumptive water use would be approximately 62 cfs (1.75 m^3/s or 40 mgd), equivalent to approximately 1.0 percent of the Rock River's average flow. The projected consumptive use under this alternative represents about 17 percent more surface water than current Byron operations, which consume approximately 52.9 cfs (1.5 m^3/s or 34.2 mgd) (see Sections 3.5.1.2 and 4.5.1.1). However, the NRC staff expects that that State would impose limits on surface water withdrawals and consumption during low river flows, similar to those currently in place for Byron, which would reduce the cited makeup water and consumptive use demands for this alternative on an annualized basis.

The NRC staff further expects that water treatment additives for new nuclear plant operations and effluent discharges would be relatively similar in quality and volume to Byron. Additionally, effluent discharges and storm water discharges would be subject to a State-issued NPDES permit, and surface water withdrawals would be subject to applicable state water appropriation and registration requirements. To prevent and respond to accidental nonnuclear releases to surface water, facility operations would be conducted in accordance with a spill prevention, control, and countermeasures plan; storm water pollution prevention plan; or equivalent plans and associated BMPs and procedures.

Based on the above, the overall impacts on surface water use and quality from construction and operations under the new nuclear alternative would be SMALL to MODERATE.

4.5.3.2 Groundwater Resources

For this alternative, as discussed in Section 4.5 of the GEIS, construction impacts for all alternatives to the proposed action on groundwater resources would be SMALL. Also as discussed in Section 4.5 of the GEIS, operational impacts for all alternatives to the proposed action on groundwater quality would be SMALL. During operations the consumptive use of groundwater would be similar to the proposed action. Therefore, the impacts of this alternative on groundwater resources would be SMALL.

4.5.4 IGCC Alternative

4.5.4.1 Surface Water Resources

Impacts from construction activities associated with the IGCC alternative on surface water resources would be expected to be similar to but somewhat greater than those under the new nuclear alternative (see Section 4.5.3.1). The potential for greater impacts is attributable to the additional land required for construction of the power blocks for four IGCC units and for excavation and construction of other onsite facilities for coal handling and storage, and for coal ash and scrubber waste management. The same assumptions for construction and operations also apply to this alternative, except as noted.

Some temporary impacts to surface water quality may result from increased sediment loading and from pollutants in stormwater runoff from disturbed areas and from excavation and dredge-and-fill activities. There also would be the potential for hydrologic and water-quality impacts to occur from the extension or refurbishment of rail spurs to transport coal and other materials to, and coal ash from, potential site locations. Use of the Byron site would have the advantage of use of the existing cooling water intake, effluent discharge, and rail infrastructure.

Regardless, as described in Section 4.5.3.1 for the new nuclear alternative, water-quality impacts would be minimized by the application of BMPs and compliance with State-issued NPDES permits for construction. Any dredge-and-fill operations would be conducted under a permit from the USACE and State-equivalent permits requiring the implementation of BMPs to minimize impacts.

Operation of an IGCC plant would require less makeup water and would have lower consumptive use than either the new nuclear alternative or current Byron operations. The projected cooling water makeup requirement for an IGCC plant under this alternative is 51 cfs (1.44 m^3/s or 33 mgd), with consumptive use of about 40 cfs (1.14 m^3/s or 26 mgd). This alternative would consume about 24 percent less surface water than current Byron operations, which consumes approximately 52.9 cfs (1.5 m^3/s or 34.2 mgd).

As summarized in Section 4.5.3.1 for the new nuclear alternative, surface water withdrawals and effluent discharges would be subject to applicable regulatory requirements under this alternative. However, management of runoff and leachate from coal and ash storage facilities would require additional regulatory oversight and would present an additional risk to surface water resources in proximity to site locations.

For this alternative, based on the projected magnitude of ground disturbance and hydrologic alteration and potential water quality impacts from coal and ash handling and management, impacts on surface water resources would range from SMALL to MODERATE.

4.5.4.2 Groundwater Resources

For this alternative, as discussed in Section 4.5 of the GEIS, construction impacts for all alternatives to the proposed action on groundwater resources would be SMALL. Also as discussed in Section 4.5 of the GEIS, operational impacts for all alternatives to the proposed action on groundwater quality would be SMALL. During operations the consumptive use of groundwater would be similar to the proposed action. Therefore, the impacts of this alternative on groundwater resources would be SMALL.

4.5.5 NGCC Alternative

4.5.5.1 Surface Water Resources

Direct impacts from construction activities associated with the NGCC alternative on surface water resources would be expected to be much smaller than those under either the new nuclear or IGCC alternative. A new NGCC plant and associated pipelines would occupy a much smaller footprint (i.e., about 94 ac (38 ha)) than the current Byron plant or the proposed new nuclear or IGCC facilities. This would result in less extensive excavation and earthwork. Otherwise, the same assumptions for construction and operations also apply to this alternative, except as noted. In particular, use of the Byron site would offer the advantage of use of the existing cooling water intake and discharge infrastructure.

Some temporary impacts to surface water quality may result from increased sediment loading and from any pollutants in stormwater runoff from disturbed areas, from excavation, and dredge-and-fill activities. Depending on the path of any required new gas pipelines and transmission lines to service the NGCC plant, some stream crossings could be necessary. However, because of the short-term nature of any required dredging and filling and stream-crossing activities, the hydrologic alterations and sedimentation would be localized and water-quality impacts would be temporary and would cease after construction has been completed and the site stabilized. The use of modern pipeline construction techniques, such as horizontal directional drilling, would further minimize the potential for water-quality impacts in the affected streams. In addition, as described in Section 4.5.3.1 for the new nuclear alternative, water-quality impacts would be minimized by the application of BMPs and compliance with State-issued NPDES permits for construction. Any dredge-and-fill operations would be conducted under a permit from the USACE and State-equivalent permits requiring the implementation of BMPs to minimize impacts.

For onsite facility operations, a five-unit NGCC plant would have a smaller cooling water demand and lower consumptive water use as compared to current Byron operations and the new nuclear and IGCC alternatives. It is projected that an NGCC plant would require approximately 26.3 cfs (0.74 m^3/s or 17 mgd) of surface water for cooling and related processes, with consumptive use totaling about 20.1 cfs (0.57 m^3/s or 13 mgd). Thus, this alternative would consume about 62 percent less surface water than current Byron operations, which consumes approximately 52.9 cfs (1.5 m^3/s or 34.2 mgd).

Based on this analysis, the overall impacts on surface water resources from construction and operations under the NGCC alternative would be SMALL.

4.5.5.2 Groundwater Resources

For this alternative, as discussed in Section 4.5 of the GEIS , construction impacts for all alternatives to the proposed action on groundwater resources would be SMALL. Also as discussed in Section 4.5 of the GEIS, operational impacts for all alternatives to the proposed action on groundwater quality would be SMALL. During operations the consumptive use of groundwater would be similar to the proposed action. Therefore, the impacts of this alternative on groundwater resources would be SMALL.

4.5.6 Combination Alternative (NGCC, Wind, Solar)

4.5.6.1 Surface Water Resources

For the NGCC component of this alternative, the impacts on surface water resources from facility construction and operations at either the Byron site or alternative sites would be a fraction of those described in Section 4.5.5.1 because the NGCC plant would be scaled back to a single 360-MW unit. As a result, operational cooling water demands would be reduced by about 85 percent.

Impacts on surface water resources from constructing up to 2,532 land-based wind turbines would primarily be limited to the relatively small amounts of water needed at each installation site for dust suppression and soil compaction during site clearing and for concrete production. Construction of utility-scale solar PV farms would require relatively large volumes of water per site due to the much larger land area required per MW of replacement power produced. For both components under this alternative, the NRC assumes that required water would be procured from offsite sources and trucked to the point of use on an as-needed basis. Water could also be supplied via a local water utility. The likely use of ready-mix concrete would also reduce the need for onsite use of nearby water sources for construction.

Installation of land-based wind turbines and utility-scale solar PV farms would also require construction of access roads and possibly transmission lines (especially for sites not already proximal to transmission line corridors). Access road construction would also require some water for dust suppression and roadbed compaction and would have the potential to result in soil erosion and stormwater runoff from cleared areas. For construction, water would likely be trucked to the point of use from offsite locations along with road construction materials. In all cases, it is expected that construction activities would be conducted in accordance with State-issued NPDES or equivalent permits for stormwater discharges associated with construction activity, which would require the implementation of appropriate BMPs to prevent or mitigate water-quality impacts. In contrast to land-based wind turbine sites and utility-scale solar PV farms, installation of small solar PV units on rooftops and at already-developed sites within the electric service ROI (see Section 2.2.2) would have little or no impact on surface water resources.

To support the operation of wind turbine and PV installations, no direct use of surface water would be expected. Water would likely be obtained from groundwater or purchased from a water utility. Regardless, only very small amounts of water would be needed to periodically clean turbine blades and motors and could be trucked to the point of use as part of routine servicing. Water also would be required to clean panels at solar PV farms or situated in rooftop arrays. Adherence to appropriate waste management and minimization plans, spill prevention practices, and pollution prevention plans during servicing of wind turbine and solar PV installations and operation of vehicles connected with site operations would minimize the risks to soils and surface water resources from spills of petroleum, oil, and lubricant products and stormwater runoff.

In consideration of these facts, the impacts on surface water resources from construction and operations under the combination alternative would be SMALL.

4.5.6.2 Groundwater Resources

For this alternative, as discussed in Section 4.5 of the GEIS , construction impacts for all alternatives to the proposed action on groundwater resources would be SMALL. Also as discussed in Section 4.5 of the GEIS, operational impacts for all alternatives to the proposed action on groundwater quality would be SMALL. During operations the consumptive use of groundwater would be much smaller than the proposed action. Therefore, the impacts of this alternative on groundwater resources would be SMALL.

4.5.7 Purchased Power

4.5.7.1 Surface Water Resources

The impacts of this alternative on surface water resources are likely to be bounded by the impact descriptions for the other alternatives, except that no new construction would be likely. Specifically, new and continued operation of nuclear, coal-fired, and natural gas-fired plants and renewable energy projects would not be expected to result in incremental impacts on surface water use and quality that are greater than those described in Sections 4.5.3, 4.5.4, 4.5.5, and 4.5.6 provided that all energy-generating facilities operate within their associated water use and NPDES permits. Therefore, the impact of this alternative on surface water resources would be expected to range from SMALL to MODERATE.

4.5.7.2 Groundwater Resources

The impacts of this alternative on groundwater resources are likely to be bounded by the impact descriptions for the other alternatives. Therefore, the impact of this alternative on groundwater resources would be SMALL.

4.6 Terrestrial Resources

This section describes the potential impacts of the proposed action (license renewal) and alternatives to the proposed action on terrestrial resources.

4.6.1 Proposed Action

Section 3.6 of this SEIS describes terrestrial resources on and in the vicinity of the Byron site. The generic (Category 1) and site-specific (Category 2) issues that apply to terrestrial resources during the proposed license renewal period appear in Table 4–7. The GEIS (NRC 2013a) discusses these issues in Section 4.6.1.1.

Table 4–7. Terrestrial Resource Issues

Issue	GEIS Section	Category
Effects on terrestrial resources (noncooling system impacts)	4.6.1.1	2
Exposure of terrestrial organisms to radionuclides	4.6.1.1	1
Cooling tower impacts on vegetation (plants with cooling towers)	4.6.1.1	1
Bird collisions with plant structures and transmission lines [a]	4.6.1.1	1
Water use conflicts with terrestrial resources (plants with cooling ponds or cooling towers using makeup water from a river)	4.6.1.1	2
Transmission line ROW management impacts on terrestrial resources [a]	4.6.1.1	1
Electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)[a]	4.6.1.1	1

[a] This issue applies only to the inscope portion of electric power transmission lines, which are defined as transmission lines that connect the nuclear power plant to the substation where electricity is fed into the regional power distribution system and transmission lines that supply power to the nuclear plant from the grid.

Source: Table B-1 in Appendix B, Subpart A, to 10 CFR Part 51

4.6.1.1 Generic Terrestrial Resource Issues

For the generic (Category 1) terrestrial resources issues listed in Table 4–7, the NRC staff did not identify any new and significant information related to the generic (Category 1) issues listed above during the review of the applicant's ER (Exelon 2013a), the site audit, or the scoping process. Therefore, the NRC staff expects no impacts associated with these issues beyond those discussed in the GEIS. The GEIS concludes that the impact level for each of these issues is SMALL.

4.6.1.2 Effects on Terrestrial Resources (Noncooling System Impacts)

In the GEIS (NRC 2013a), the NRC staff determined that noncooling system effects on terrestrial resources is a Category 2 issue (see Table 4–7) that requires site-specific evaluation during each license renewal review. According to the GEIS, noncooling system impacts can include those impacts that result from landscape maintenance activities, stormwater management, elevated noise levels, and other ongoing operations and maintenance activities that would occur during the renewal period and that could affect terrestrial resources on and near the Byron site.

Section 3.6 indicates that approximately 1,244 ac (503 ha) of the Byron site (70 percent) remains as natural areas that are either leased for agricultural use or as unmanaged forest, meadow, or grassland habitat (Exelon 2014). The majority of site landscape maintenance is performed within the protected area and not within natural areas on the site. Typically, only trees and shrubs that pose a safety or security threat are removed from natural areas. Leased lands are maintained by the leasee in accordance with the standing lease.

Stormwater on the Byron site drains into the Construction Runoff Pond. From the pond, water either flows into the Unit 2 natural draft cooling tower basin where it becomes part of the circulating water system, or it flows through NPDES Outfall 003 via drainage ditches located along German Church Road to the north of the main plant complex (Exelon 2013a). Special Condition 16 of the NPDES permit requires Exelon to develop and implement a Stormwater Pollution Prevention Plan (Exelon 2013a). This plan identifies sources of pollution that could affect the quality of stormwater and describes practices that Exelon uses to reduce such pollutants. Areas with spill potential, such as areas around tanks that contain oil, are further monitored under the Byron Station Spill Prevention Control and Countermeasure Plan. Collectively, these measures ensure that the effects to terrestrial resources from pollutants carried by stormwater would be small during the proposed license renewal term.

The GEIS (NRC 2013a) indicates that elevated noise levels could be a noncooling system impact to terrestrial resources. However, the GEIS also concludes that generic noise impacts would be small because noise levels would remain well below regulatory guidelines for offsite receptors during continued operations and refurbishment associated with license renewal. The NRC staff did not identify any information during its review that would indicate that noise impacts to terrestrial resources at Byron would be unique or require separate analysis.

Other operations and maintenance activities that could occur in the future include the replacement of the Unit 2 steam generators (SGs). While Exelon has previously replaced the Unit 1 SGs, Exelon has not replaced the Unit 2 SGs. Exelon has no plans to replace the Unit 2 SGs at this time, but may choose to replace them prior to the end of the 40-year initial license term. Because SG replacement is not necessary for safe operation during license renewal, the NRC does not consider it part of the proposed action. As such, the impacts of Unit 2 SG replacement on terrestrial resources are discussed in Section 4.16.4 rather than in this section. Exelon (2013a) is planning no other land-disturbing activities or construction unrelated to possible Unit 2 SG replacement. No disturbances to natural habitats would occur during license renewal, and Exelon does not expect any changes in operations or changes to existing land uses during the proposed license renewal period. As such, no measurable impacts to the terrestrial environment are expected during the license renewal period.

When new activities that could impact the environment occur at Byron, Exelon follows several procedures to ensure that potential environmental effects are considered and appropriately addressed. Exelon maintains a procedure (No. EN-AA-103) that requires Exelon staff to screen proposed activities, such as maintenance activities, operational changes, procedure changes, and other facility activities, to determine if the activity warrants further evaluation for environmental impact or risk (Exelon 2013b). If the activity warrants further evaluation, Exelon Procedure No. EN-AA-103-F-02 provides guidance to Exelon staff on performing such an evaluation and determining the environmental and regulatory impacts of the activity (Exelon 2013b). This procedure also requires that implementation of the activity be halted until any environmental impacts are addressed.

Based on the NRC staff’s independent review, the staff concludes that the landscape maintenance activities, stormwater management, elevated noise levels, and other ongoing operations and maintenance activities that Exelon might undertake during the renewal term would primarily be confined to disturbed areas of the Byron site. These activities would not have noticeable effects on terrestrial resources, nor would they destabilize any important attribute of the terrestrial resources on or in the vicinity of the Byron site. Therefore, the NRC staff expects noncooling system impacts on terrestrial resources during the license renewal term to be SMALL.

4.6.1.3 Water Use Conflicts with Terrestrial Resources (Plants with Cooling Ponds or Cooling Towers Using Makeup Water from a River)

In the GEIS (NRC 2013a), the NRC staff determined that effects of water use conflicts on terrestrial resources is a Category 2 issue (see Table 4–7) that requires site-specific evaluation during each license renewal review. Water use conflicts occur when the amount of water needed to support terrestrial resources is diminished as a result of demand for agricultural, municipal, or industrial use or decreased water availability due to droughts, or a combination of these factors.

Section 4.5.1.1 addresses surface water use conflicts and concludes that the potential impacts on surface water resources and downstream water availability from Byron's consumptive water use during the license renewal term would be SMALL because the State of Illinois imposes withdrawal restrictions to ensure adequate instream and downstream flows. Section 4.7.1.2 addresses water use conflicts with aquatic resources and determines that Byron has consumed a very small amount (between 0.7 and 1.7 percent) of the Rock River's flow each year for the past 12 years, under the conservative assumption that Byron was operating at 100 percent power at all times. This section concludes that the impacts of water use conflicts would be SMALL for terrestrial resources. The NRC staff finds no other impacts that would be experienced by riparian or other terrestrial habitats that are not discussed in Sections 4.5.1.1 or 4.7.1.2. Accordingly, the NRC staff concludes that the impact of water use conflicts on terrestrial resources from the proposed license renewal would be SMALL.

4.6.2 No-Action Alternative

If Byron were to shut down, the impacts to terrestrial ecology would remain similar to those during operations until the plant is fully decommissioned. Temporary buildings and staging or laydown areas may be required during large component and structure dismantling. Byron is likely to have sufficient space within previously disturbed areas for these needs, and therefore, no additional land disturbances would occur on previously undisturbed land. Adjacent lands may experience temporary increases in erosional runoff, dust, or noise, but these impacts could be minimized with the implementation of standard BMPs (NRC 2002). In NUREG–0586, *Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities, Supplement 1*, NRC (2002) concludes generically that impacts to terrestrial ecology during decommissioning activities would be SMALL. Reclamation of the site following decommissioning could create terrestrial habitat in areas currently used as industrial areas. The GEIS (NRC 2013a) notes that terrestrial resource impacts could occur in other areas beyond the immediate nuclear plant site as a result of the no-action alternative if new power plants are needed to replace lost capacity. The NRC staff concludes that the no-action alternative is unlikely to noticeably alter or have more than minor effects on terrestrial resources. Thus, the NRC staff concludes that the impacts of the no-action alternative on terrestrial resources during the proposed license renewal term would be SMALL.

4.6.3 New Nuclear Alternative

The new nuclear alternative assumes that the new facility would be built at an existing nuclear or retired coal plant site within the ROI but outside of Illinois. Construction of the new nuclear plant would require an estimated 324 ac (131 ha) for permanent buildings and facilities and an additional 31 ac (12.5 ha) for temporary facilities and laydown areas. The NRC staff assumes that this alternative would use existing onsite structures and previously disturbed areas to the extent practicable to minimize new development in undisturbed areas. However, given the land requirements, it is expected that some undisturbed areas would be affected, which would directly impact terrestrial resources. During construction, terrestrial species could experience habitat loss or fragmentation, loss of food resources, and altered behavior due to noise and other construction-related disturbances. Erosion and sedimentation from clearing, leveling, and excavating land could affect adjacent riparian and wetland habitats, if present. Implementation of appropriate BMPs would minimize these effects. This alternative could also require construction of new transmission lines or upgrades to existing lines. Because the new nuclear facility would be located on an existing energy-producing site, transmission lines could likely be colocated within existing transmission line corridors to minimize land disturbance. Although construction activities could noticeably alter terrestrial resources through habitat loss or fragmentation, construction is unlikely to destabilize any important attributes of the terrestrial environment. The exact magnitude of impacts would vary based on the chosen location of the facility and the amount and types of undisturbed habitat that would be affected by construction of the alternative, and thus, impacts of construction could range from SMALL to MODERATE.

During operation, impacts would be similar in type and magnitude to those assessed in Section 4.6.1 for continued operation of Byron under the proposed renewal term and would, therefore, be SMALL.

The NRC concludes that the impacts of construction and operation of the new nuclear alternative on terrestrial resources would be SMALL to MODERATE.

4.6.4 IGCC Alternative

The IGCC alternative assumes that the new facility would be built at an existing energy-producing site or a retired coal plant site in Illinois or another state within the ROI. The facility would require 2,000 ac (809 ha) of land to construct the facility. The NRC staff assumes that this alternative would use existing onsite structures and previously disturbed areas to the extent practicable to minimize new development in undisturbed areas. However, because the footprint of the facility would be large, it is likely that construction would require clearing of previously undisturbed terrestrial habitats. This would result in habitat loss and fragmentation and loss of food resources. Terrestrial species may also alter their behaviors due to noise and other construction-related disturbances. Erosion and sedimentation from clearing, leveling, and excavating land could affect adjacent riparian and wetland habitats, if present. Implementation of appropriate BMPs would minimize these effects. This alternative could also require construction of new transmission lines or upgrades to existing lines. Because the IGCC facility would be located on an existing energy-producing site, any new transmission lines could likely be colocated within existing transmission line corridors to minimize land disturbance. Depending on the site and terrestrial habitats present, construction activities could noticeably alter or destabilize attributes of the terrestrial environment due to the large land requirements of the facility. The exact magnitude of impacts would vary based on the chosen location of the facility and the amount and types of undisturbed habitat that would be affected by construction of the alternative. The NRC staff expects that impacts of construction on terrestrial resources would be MODERATE.

The GEIS (NRC 2013a) concludes that impacts to terrestrial resources from operation of fossil energy alternatives would essentially be similar to those from continued operations of a nuclear facility. Unique impacts would include periodic maintenance dredging if coal is delivered by barge, which could create noise, dust, and sedimentation. Dredging and delivery of coal to the site could introduce minerals and trace elements to water resources on which terrestrial biota rely. Such minerals could also bioaccumulate in nearby riparian or wetland habitats. Air emissions during operation would include sulfur oxides and nitrogen oxides, which can combine with water vapor and create sulfuric and nitric acids. These acids would then be released back into the environment through precipitation, which could affect the acidity levels of water resources and have detrimental effects to plant foliage. Acid precipitation has the potential to destabilize the terrestrial environment by creating conditions that are too acidic for certain plants or animals. The IGCC facility would also emit various GHGs during operation, which is an effect that can have far-reaching consequences because GHGs contribute to climate change. The effects of climate change on terrestrial resources are discussed in Section 4.13.3.2. The various air emissions during operation of the IGCC facility could create noticeable impacts that could destabilize certain attributes of the terrestrial environment, and therefore, the operational impacts would be MODERATE.

The NRC concludes that the impacts of construction and operation of the IGCC alternative on terrestrial resources would be MODERATE.

4.6.5 NGCC Alternative

The NGCC alternative assumes that the facility would be built at an existing energy-producing site or a retired coal plant site in Illinois or another state within the ROI. The facility would require 94 ac (38 ha) of land for the plant and associated pipelines. Because the footprint of the facility would be relatively small, the entire construction footprint could likely be sited in already developed areas of the site, which would minimize impacts to terrestrial habitats and species. However, the level of direct impact would vary based on the specific location of new buildings and infrastructure on the site. During construction, terrestrial species could experience habitat loss or fragmentation, loss of food resources, and altered behavior due to noise and other construction-related disturbances. Erosion and sedimentation from clearing, leveling, and excavating land could affect adjacent riparian and wetland habitats, if present. Implementation of appropriate BMPs would minimize these effects. This alternative could also require construction of new transmission lines or upgrades to existing lines. Because the NGCC facility would be located on an existing site, any new transmission lines could likely be colocated within existing transmission line corridors to minimize land disturbance. Similarly, any new pipelines could be colocated within existing pipeline corridors. Although construction activities could noticeably alter terrestrial resources, primarily through habitat loss or fragmentation, construction is unlikely to destabilize any important attributes of the terrestrial environment. The exact magnitude of impacts would vary based on the chosen location of the facility and the amount and types of undisturbed habitat that would be disturbed for construction of the alternative, and thus, impacts of construction could range from SMALL to MODERATE.

The GEIS (NRC 2013a) concludes that impacts to terrestrial resources from operation of fossil energy alternatives would essentially be similar to those from continued operations of a nuclear facility. Unique impacts would include air emissions of GHGs such as nitrogen oxides, carbon dioxide, and methane, all of which can have far-reaching consequences because they contribute to climate change. The effects of climate change on terrestrial resources are discussed in Section 4.13.3.2. Although the impacts of operating the NGCC alternative may be noticeable, they are unlikely to destabilize any important attribute of the terrestrial environment and would, therefore, be SMALL.

The NRC concludes that the impacts of construction and operation of the NGCC alternative on terrestrial resources would be SMALL to MODERATE.

4.6.6 Combination Alternative (NGCC, Wind, Solar)

The NGCC component of this alternative would require the same amount of land as the NGCC alternative (94 ac (38 ha)), but the NGCC component would likely make better use of existing infrastructure because it would be sited at an existing power plant in Illinois or another state within the ROI and could use buildings and structures that are already in place and operational for the existing facility. The types of impacts on the terrestrial environment would be similar to those discussed in Section 4.6.5, but the NRC staff expects the magnitude of impacts to be less because of the use of existing infrastructure. Thus, the impacts of construction and operation of the NGCC component of the combination alternative would be SMALL.

The wind component of the combination alternative would require 3,376 ac (1,366 ha) to 10,127 ac (4,098 ha) at sites across the ROI. However, the majority of this land would only be temporarily disturbed during construction. Permanently disturbed land would hold the wind turbines, access roads, and transmission lines. Land used for equipment laydown and turbine component assembly and erection could be returned to its original state. Use of BMPs would ensure that disturbed lands were appropriately restored to reduce the long-term impacts to the terrestrial environment. Operation of wind turbines could uniquely affect terrestrial species through mechanical noise, collision with turbines and meteorological towers, and interference with migratory behavior. Bat and bird mortality from turbine collisions is an ongoing concern for operating wind farms; however, recent developments in turbine design have reduced the potential for bird and bat strikes. The NRC staff expects that this component has the potential to noticeably alter terrestrial resources, primarily through the loss of habitat and bird and bat mortalities associated with wind turbine operation. However, it is unlikely that the wind component would destabilize any important attribute of the terrestrial environment, and thus, impacts would be MODERATE.

The solar component would require 6,749 ac (2,731 ha) of land across the ROI. The majority of solar installations could be installed on building roofs at existing residential, commercial, or industrial sites or at larger standalone solar facilities, and thus, it is possible that little terrestrial habitat would be disturbed during construction. However, the exact magnitude of impacts on terrestrial resources would depend on the amount of terrestrial habitat that is lost or fragmented during construction of solar installations. Operation would have no measurable effects on the terrestrial environment. Overall impacts from construction and operation of this component of the alternative would range from SMALL to MODERATE depending on the locations of solar installations and the amount of terrestrial habitat affected.

The NRC staff concludes that the impacts of the combination alternative on terrestrial resources would be SMALL to MODERATE.

4.6.7 Purchased Power

The purchased power alternative would have wide-ranging impacts that are hard to specifically assess because this alternative could include a mixture of coal, natural gas, nuclear, and wind across many different sites in the ROI. This alternative would likely have little to no construction impacts because it would include power from already-existing power generating facilities. The construction of additional transmission lines would require implementation of BMPs to minimize erosion and sedimentation that could affect riparian areas and wetlands. The types of operational impacts would be similar to the effects discussed in the preceding alternative sections. This alternative would be more likely to intensify already-existing effects at power generating facilities than create wholly new effects on terrestrial species and habitats. Existing facilities would likely have BMPs and other procedures in place to ensure that effects to the environment during operations are minimized. The NRC staff concludes that the impacts on terrestrial resources from the purchased power alternative would be SMALL.

4.7 Aquatic Resources

This section describes the potential impacts of the proposed action (license renewal) and alternatives to the proposed action on aquatic resources.

4.7.1 Proposed Action

Section 3.1.3 of this SEIS describes the Byron cooling and auxiliary water systems, and Section 3.7 describes the aquatic resources. The generic (Category 1) and site-specific (Category 2) issues that apply to aquatic resources at Byron during the proposed license renewal period appear in Table 4–8. The GEIS (NRC 2013a) discusses these issues in Section 4.6.1.2.

Table 4–8. Aquatic Resource Issues

Issue	GEIS Section	Category
All plants		
Entrainment of phytoplankton and zooplankton	4.6.1.2	1
Infrequently reported thermal impacts	4.6.1.2	1
Effects of cooling water discharge on dissolved oxygen, gas supersaturation, and eutrophication	4.6.1.2	1
Effects of nonradiological contaminants on aquatic organisms	4.6.1.2	1
Exposure of aquatic organisms to radionuclides	4.6.1.2	1
Effects of dredging on aquatic organisms	4.6.1.2	1
Effects on aquatic resources (noncooling system impacts)	4.6.1.2	1
Impacts of transmission line ROW management on aquatic resources [a]	4.6.1.2	1
Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	4.6.1.2	1
Plants with cooling towers		
Impingement and entrainment of aquatic organisms	4.6.1.2	1
Thermal impacts on aquatic organisms	4.6.1.2	1
Plants with cooling ponds or cooling towers using makeup water from a river		
Water use conflicts with aquatic resources	4.6.1.2	2

[a] This issue applies only to the inscope portion of electric power transmission lines, which are defined as transmission lines that connect the nuclear power plant to the substation where electricity is fed into the regional power distribution system and transmission lines that supply power to the nuclear plant from the grid.

Source: Table B-1 in Appendix B, Subpart A, to 10 CFR Part 51

4.7.1.1 Generic GEIS Issues

The GEIS (NRC 2013a) concludes that the 11 Category 1 issues listed in Table 4–8 would have a SMALL impact on aquatic resources during the license renewal term for all plants. For these issues, no additional plant-specific analysis is required unless new and significant information is identified.

During its review, the NRC staff considered Exelon's ER, aquatic surveys and studies performed at Byron and in the Rock River, and available scientific literature; conducted a site audit; and considered Federal and State agency and public comments received during the scoping process. The NRC staff did not identify any new and significant information related to any of the Category 1 issues. Therefore, no site-specific analysis is required for these issues, and there would be no impacts associated with these issues beyond those discussed in the GEIS.

4.7.1.2 Water Use Conflicts With Aquatic Resources

In the GEIS (NRC 2013a), the NRC staff determined that effects of water use conflicts on aquatic resources is a Category 2 issue (see Table 4–8) that requires site-specific evaluation during each license renewal review. Water use conflicts occur when the amount of water needed to support aquatic resources is diminished as a result of demand for agricultural, municipal, or industrial use or decreased water availability due to droughts, or a combination of these factors.

According to USGS (2014) data from the nearest surface water gaging station (USGS Station No. 05440700), the average annual flow of the Rock River at Byron, Illinois, in the past 12 data years (2001 through 2012) has ranged from 4,834 cfs (139,900 liters per second (L/s) or 2.17 million gallons per minute (gpm)) in 2012 to 12,090 cfs (342,400 L/s or 5.43 million gpm) in 2008. At 100 percent power, Byron's circulating water system withdraws an average of 2,320 L/s (36,750 gpm) of makeup water. Thus, Byron uses between 0.7 and 1.7 percent of the Rock River's flow each year for the past 12 years, under the conservative assumption that Byron was operating at 100 percent power at all times. In times when the river flow is low, Byron has an agreement with the Illinois Department of Natural Resources (IDNR) to limit Rock River water consumption to no more than 9 percent of total river flow when flow is less than 19,200 L/s (679 cfs) (Exelon 2013a). The amount of Rock River water Byron consumes is minor in comparison to the flow of water past the plant, and regulatory mechanisms are in place to ensure that Byron does not consume an amount that would be harmful to aquatic biota during low river flow conditions. The fish species described in Section 3.7 that occur in the Rock River in the vicinity of the Byron site do not appear to be affected by the consumption of water from the river. The NRC staff concludes that the impact of water use conflicts on aquatic resources from the proposed license renewal would be SMALL.

4.7.2 No-Action Alternative

If Byron were to cease operating, impacts to aquatic ecology would decrease or stop following reactor shutdown. Some withdrawal of water from the Rock River would continue during the shutdown period as the fuel is cooled, although the amount of water withdrawn would decrease over time. The reduced demand for cooling water would further decrease the effects of impingement, entrainment, and thermal effluents, which were determined to be SMALL for Byron during the proposed license renewal term (see Section 4.7.1.1). These effects would likely stop following the removal of fuel assemblies from the reactor cores.

NUREG–0586, *Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities, Supplement 1*, concludes generically that impacts to aquatic ecology during decommissioning activities would be SMALL for facilities at which the decommissioning activities would be limited to existing operational areas (NRC 2002). In the case of Byron, the NRC staff did not identify any effects that would have more than minor impacts on aquatic resources. Thus, the NRC staff concludes that the impacts of the no-action alternative on aquatic resources during the proposed license renewal term would be SMALL.

4.7.3 New Nuclear Alternative

Construction of a new nuclear alternative would occur at an existing power plant site (other than the Byron site) or at a retired coal plant site outside of Illinois. Construction activities could degrade water quality of nearby streams, ponds, or rivers through erosion and sedimentation; result in loss of habitat through pond or wetland filling; or result in direct mortality of aquatic organisms from dredging or other inwater work. Due to the short-term nature of construction activities, these effects would likely be relatively localized and temporary. Siting the plant on an existing site could make use of existing transmission lines, roads, parking areas, and other infrastructure, which would limit the amount of habitat disturbance that would be required. Less habitat disturbance would create less erosion and sedimentation. The construction of intake and discharge structures could result in direct mortality of individuals as well as water quality degradation. Appropriate permits would ensure that water quality impacts would be addressed through mitigation or BMPs, as stipulated in the permits. The U.S. Environmental Protection Agency, USACE, or the State would oversee applicable permitting, including a Clean Water Act Section 404 permit, Section 401 certification, and Section 402(p) NPDES general stormwater permit. The NRC (2013g) has completed the review of one combined license (COL) application to build and operate a new nuclear plant in the ROI (Enrico Fermi 3 in Michigan) and found that construction would have SMALL impacts on aquatic resources. Without more specific details on the location of the new nuclear alternative, the NRC staff finds it reasonable to adopt previous conclusions regarding Enrico Fermi 3 for the construction portion of this alternative.

Operational impacts would include those listed in Table 4–8, and the GEIS (NRC 2013a) conclusions of SMALL for Category 1 issues in the table would apply during the operational phase of the new nuclear alternative. Water use conflicts with aquatic resources would depend on the site location, water body, and specific aquatic community present and cannot be determined without more-specific details on the location of this alternative.

The NRC staff concludes that the impacts to aquatic resources from construction and operation of a new nuclear alternative would be SMALL.

4.7.4 IGCC Alternative

Construction of an IGCC alternative would occur at the Byron site or another existing power plant site in the ROI. The GEIS (NRC 2013a) indicates that the impacts of new power plant construction on ecological resources would be qualitatively similar. Thus, those impacts discussed under the new nuclear alternative would apply during the construction phase. Because the IGCC alternative would require significantly more land than the new nuclear alternative (2,000 ac (809 ha) versus 355 ac (144 ha)), the magnitude of impacts would likely be greater and could create noticeable effects on aquatic resources. Thus, construction impacts would be MODERATE.

Operation of the IGCC alternative would require less cooling water than Byron. Accordingly, impingement, entrainment, and thermal effects on aquatic resources would likely be smaller than for continued operation of Byron, though the exact magnitude would depend upon the water body and specific aquatic communities present. Chemical discharges from the cooling system would be similar to those at Byron. Operation would require coal deliveries, cleaning, and storage, which would require periodic dredging (if coal is delivered by barge); create dust, sedimentation, and turbidity; and introduce trace elements and minerals into the water. Air emissions from the IGCC units would include small amounts of sulfur dioxide, particulates, and mercury that would settle on water bodies or be introduced into the water from soil erosion. If the IGCC plant were located on the same water body (the Rock River) in the vicinity of the Byron site, overall operational impacts would be similar to the continued operation of Byron with the exception of air emissions. However, without knowing the location of the IGCC plant, the associated water body, aquatic species, and their interactions within the ecosystem, the NRC staff cannot assume that overall impacts of operation of an IGCC plant would not create noticeable effects on the aquatic environment. Thus, impacts could range from SMALL to MODERATE.

The NRC staff concludes that the impacts to aquatic resources from construction of an IGCC plant would be MODERATE and the impacts of operation would be within the range of SMALL to MODERATE.

4.7.5 NGCC Alternative

Construction of an NGCC alternative would occur at the Byron site or another existing power plant site in the ROI. The GEIS (NRC 2013a) indicates that the impacts of new power plant construction on ecological resources would be qualitatively similar. Thus, those impacts discussed under the new nuclear alternative would apply during the construction phase. Construction of new pipelines, if necessary, could impact previously undisturbed habitats. This impact would vary depending on the location of the plant and would be more likely to impact terrestrial resources than aquatic resources. Because the NGCC alternative would be built on an existing power plant site, new pipelines could be colocated in existing corridors to reduce impacts. Overall, construction impacts would be SMALL.

Operation of the NGCC alternative cooling system would be qualitatively similar to the IGCC alternative but would result in smaller impacts because the NGCC alternative would consume less cooling water. Air emissions from the NGCC units would include nitrogen oxide, carbon dioxide, and particulates that would settle on water bodies or be introduced into the water from soil erosion. If the NGCC plant were located on the same water body (the Rock River) in the vicinity of the Byron site, overall operational impacts would be less than for the continued operation of Byron. However, without knowing the location of the NGCC plant, the associated water body, aquatic species, and their interactions within the ecosystem, the NRC staff cannot assume that overall impacts of operation of an NGCC plant would not create noticeable effects on the aquatic environment. Thus, impacts could range from SMALL to MODERATE.

The NRC staff concludes that the impacts to aquatic resources from construction of an NGCC plant would be SMALL and the impacts of operation would be within the range of SMALL to MODERATE.

4.7.6 Combination Alternative (NGCC, Wind, Solar)

The NGCC portion of this alternative could be located at the Byron site or another existing power plant site in the ROI. Construction and operation impacts would be qualitatively similar to those discussed for the NGCC alternative, but would be much lower in magnitude due to the smaller footprint of the plant, reduced cooling water consumption, and lowered air emissions. The wind and solar portions of the alternative, which account for 90 percent of the alternative's power generation, would not require cooling or consumptive water use during operation, and thus, would not affect aquatic resources. The NRC staff concludes that the impacts on aquatic resources from the combination alternative would be SMALL.

4.7.7 Purchased Power

The purchased power alternative would have wide-ranging impacts that are hard to specifically assess because this alternative could include a mixture of coal, natural gas, nuclear, and wind across many different sites in the ROI. This alternative would likely have little to no construction impacts because it would include power from already-existing power generating facilities. The construction of additional transmission lines would require implementation of BMPs to minimize erosion and sedimentation in nearby streams, ponds, or rivers. The types of operational impacts would be similar to the effects discussed in the preceding alternative sections. This alternative would be more likely to intensify already-existing effects at power generating facilities than create wholly new effects on aquatic species and habitats. Existing facilities would likely have BMPs and other procedures in place to ensure that effects to the environment during operations are minimized. The NRC staff concludes that the impacts on aquatic resources from the purchased power alternative would be SMALL.

4.8 Special Status Species and Habitats

This section describes the potential impacts of the proposed action (license renewal) and alternatives to the proposed action on special status species and habitats.

4.8.1 Proposed Action

Section 3.8 of this SEIS describes the special status species and habitats that have the potential to be affected by the proposed action. The discussion of species and habitats protected under the Endangered Species Act of 1973 (16 U.S.C. § 1531 et seq., herein referred to as ESA), includes a description of the action area as defined by the ESA section 7 regulations at 50 CFR 402.02. The action area encompasses all areas that would be directly or indirectly affected by the proposed Byron license renewal.

Table 4–9 lists the one Category 2 issue related to special status species and habitats identified in the GEIS (NRC 2013a). Appendix D.1 contains information on the NRC staff's section 7 consultation with the U.S. Fish and Wildlife Service (FWS) for the proposed action. The NRC did not consult with the National Marine Fisheries Service (NMFS) as part of the Byron license renewal review because (as described in Sections 3.8 and 4.8.1.1) no species or habitats under NMFS's jurisdiction occur within the action area.

Table 4–9. Special Status Species and Habitat Issues

Issue	GEIS Section	Category
Threatened, endangered, and protected species, critical habitat and essential fish habitat	4.6.1.3	2

Source: Table B-1 in Appendix B, Subpart A, to 10 CFR Part 51

4.8.1.1 Species and Habitats Protected Under the Endangered Species Act

<u>Species and Habitats Under the FWS's Jurisdiction</u>

Section 3.8 considers whether the four Federally listed species and one proposed species identified in Table 4–10 occur in the action area based on each species' habitat requirements, life history, and other available information. In that section, the NRC staff concludes that none of these species are likely to occur in the action area. The NRC staff also concludes that no candidate species, or proposed or designated critical habitat occur in the action area. Thus, the NRC staff concludes that the proposed action would have no effect on Federally listed species or habitats under FWS's jurisdiction.

If in the future, a Federally listed species is observed on the Byron site, the NRC has measures in place to ensure that NRC staff would be appropriately notified so that the NRC staff could determine the appropriate course of action, such as possibly reinitiating section 7 consultation under the ESA with the FWS at that time. Byron's operating licenses, Appendix B, "Environmental Protection Plan," Section 4.1, "Unusual or Important Environmental Events" (NRC 1985, 1987) require Exelon to report to the NRC within 24 hours any occurrence of a species protected by the ESA on the Byron site. Additionally, the NRC's regulations containing notification requirements require that operating nuclear power reactors report to the NRC within 4 hours "any event or situation, related to…protection of the environment, for which a news release is planned or notification to other government agencies has been or will be made" (Title 10 of the *Code of Federal Regulations* (10 CFR) 50.72(b)(2)(xi)). Such notifications include reports regarding Federally listed species, as described in Section 3.2.12 of NUREG–1022, *Event Report Guidelines: 10 CFR 50.72 and 50.73* (NRC 2013b).

Table 4–10. Effect Determinations for Federally Listed Species

Species	Common Name	Federal Status [(a)]	Effect Determination
	Mammals		
Myotis septentrionalis	northern long-eared bat	P	no effect
Myotis sodalis	Indiana bat	E	no effect
	Plants		
Lespedeza leptostachya	prairie bush clover	T	no effect
Platanthera leucophaea	eastern prairie fringed orchid	T	no effect
Dalea foliosa	leafy prairie clover	E	no effect

[(a)] E = endangered; T = threatened; P = proposed for Federal listing

Sources: Exelon 2013a; FWS 2013a, 2013b

Species and Habitats Under NMFS's Jurisdiction

As discussed in Section 3.8, no species or habitats under NMFS's jurisdiction occur within the action area. Thus, the NRC staff concludes that the proposed action would have no effect on Federally listed species or habitats under NMFS's jurisdiction.

Cumulative Effects

The ESA regulations at 50 CFR 402.12(f)(4) direct Federal agencies to consider cumulative effects as part of the proposed action effects analysis. Under the ESA, cumulative effects are defined as "those effects of future State or private activities, not involving Federal activities, that are reasonably certain to occur within the action area of the Federal action subject to consultation" (50 CFR 402.02). Unlike the NEPA definition of cumulative impacts (see Section 4.16), cumulative effects under the ESA do not include past actions or other Federal actions requiring separate ESA section 7 consultation. When formulating biological opinions under formal section 7 consultation, the FWS and NMFS (1998) consider cumulative effects when determining the likelihood of jeopardy or adverse modification. Therefore, consideration of cumulative effects under the ESA is necessary only if listed species will be adversely affected by the proposed action (FWS 2014).

In the case of Byron, because the NRC staff concluded earlier in this section that the proposed license renewal would have no effect on listed, proposed, or candidate species or on designated or proposed critical habitat, consideration of cumulative effects is not necessary.

4.8.1.2 Species and Habitats Protected Under the Magnuson–Stevens Act

As discussed in Section 3.8, NMFS has not designated essential fish habitat (EFH) pursuant to the Magnuson–Stevens Fishery Conservation and Management Act, as amended (16 U.S.C. §§ 1801–1884; herein referred to as MSA) in the Rock River. Thus, the NRC staff concludes that the proposed action would have no effect on EFH.

4.8.2 No-Action Alternative

Under the no-action alternative, Byron would shut down. Federally listed species and designated critical habitat can be affected not only by operation of nuclear power plants but also by activities during shutdown. The ESA action area for the no-action alternative would most likely be the same or similar to the action area described in Section 3.8. The plant would require substantially less cooling water, so potential impacts to aquatic species and habitats would be reduced, although the plant would still require some cooling water for some time. Changes in land use and other shutdown activities might affect terrestrial species differently than under continued operation.

Because no Federally listed species or habitats occur in the action area, the no-action alternative would likely have no effect on any such species or habitats. However, NRC would assess the need for ESA consultation upon plant shutdown. The ESA forbids “take” of a listed species, where “take” means “harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or attempt to engage in any such conduct.” In the case of a take, ESA section 7 requires that NRC initiate consultation with the FWS or NMFS. The implementing regulations at 50 CFR 402.16 also direct Federal agencies to reinitiate consultation in circumstances where (a) the incidental take limit in a biological opinion is exceeded, (b) new information reveals effects to Federally listed species or designated critical habitats that were not previously considered, (c) the action is modified in a manner that causes effects not previously considered, or (d) new species are listed or new critical habitat is designated that may be affected by the action. An ESA section 7 consultation could identify impacts on Federally listed species or critical habitat, require monitoring and mitigation to minimize such impacts, and provide a level of exempted takes. Regulations and guidance regarding the ESA section 7 consultation process are provided in 50 CFR Part 402 and in the *Endangered Species Consultation Handbook* (FWS and NMFS 1998).

The effects on ESA-listed aquatic species would likely be smaller than the effects under continued operation but would depend on the listed species and habitats present when the alternative is implemented. The types and magnitudes of adverse impacts to terrestrial ESA-listed species would depend on the shutdown activities and the listed species and habitats present when the alternative is implemented, and thus, the NRC cannot forecast a particular level of impact for this alternative.

4.8.3 New Nuclear Alternative

This alternative entails shutdown and decommissioning of Byron and construction of a new nuclear alternative at an existing power plant site (other than the Byron site) or at a retired coal plant site outside of Illinois. Section 4.8.2 discusses ESA considerations for the shutdown of Byron.

Because the new nuclear alternative would be built outside of Illinois, the special status species and habitats affected by the action would be different from those considered under the proposed action. Because NRC would remain the licensing agency under this alternative, the ESA would require NRC to initiate consultation with the FWS and NMFS, as applicable, prior to construction to ensure that the construction and operation of the new nuclear plant would not adversely affect any Federally listed species or adversely modify or destroy designated critical habitat.

In the unlikely event that the new nuclear plant is sited in an area that could affect water bodies with designated EFH, which applies to only certain commercially harvested marine and anadromous fish species, consultation with NMFS under the MSA would be required to assess potential impacts to that habitat.

Because the types and magnitudes of adverse impacts to ESA-listed species and EFH would depend on the proposed site, plant design, operation, and species and habitats listed when the alternative is implemented, the NRC cannot forecast a particular level of impact for this alternative.

4.8.4 IGCC Alternative

This alternative entails shutdown and decommissioning of Byron and construction of a new IGCC facility at the Byron site or another existing power plant site in the ROI. Section 4.8.2 discusses ESA considerations for the shutdown of Byron.

Unlike the new nuclear alternative, the NRC does not license IGCC facilities, and the NRC would not be responsible for initiating section 7 consultation if listed species or habitats might be adversely affected under this alternative. The facilities themselves would be responsible for protecting listed species because the ESA forbids take of a listed species.

If the IGCC alternative were to be built on the Byron site, the ESA action area might be different, and the activities and structures associated with the site would be different from those described for the proposed license renewal. If the IGCC alternative were to be built on a site other than the Byron site, the listed species and habitats affected by the action would be different from those identified for Byron. Because the types and magnitudes of adverse impacts to ESA-listed species would depend on the proposed site, plant design, operation, and species and habitats listed when the alternative is implemented, the NRC cannot forecast a particular level of impact for this alternative.

4.8.5 NGCC Alternative

This alternative entails shutdown and decommissioning of Byron and construction of a new NGCC facility at the Byron site or another existing power plant site in the ROI. Section 4.8.2 discusses ESA considerations for the shutdown of Byron.

Unlike the new nuclear alternative, the NRC does not license NGCC facilities, and the NRC would not be responsible for initiating section 7 consultation if listed species or habitats might be adversely affected under this alternative. The facilities themselves would be responsible for protecting listed species because the ESA forbids take of a listed species.

If the NGCC alternative were to be built on the Byron site, the ESA action area might be different, and the activities and structures associated with the site would be different from those described for the proposed license renewal. If the NGCC alternative were to be built on a site other than the Byron site, the listed species and habitats affected by the action would be different from those identified for Byron. Because the types and magnitudes of adverse impacts to ESA-listed species would depend on the proposed site, plant design, operation, and species and habitats listed when the alternative is implemented, the NRC cannot forecast a particular level of impact for this alternative.

4.8.6 Combination Alternative (NGCC, Wind, Solar)

This alternative entails shutdown and decommissioning of Byron and construction and operation of a new NGCC plant at the Byron site or another existing power plant site in the ROI as well as wind turbines and solar PV systems throughout the ROI. Section 4.8.2 discusses ESA considerations for the shutdown of Byron.

Unlike the new nuclear alternative, the NRC does not license NGCC, wind, and solar facilities, and the NRC would not be responsible for initiating section 7 consultation if listed species or habitats might be adversely affected under this alternative. The facilities themselves would be responsible for protecting listed species because the ESA forbids take of a listed species.

If part of the combination alternative were to be built on the Byron site, the ESA action area might be different, and the activities and structures associated with the site would be different from those described under continued operation. If parts of the combination alternative were to be built on a site or sites other than the Byron site, the listed species and habitats affected by the action would be different from those identified for Byron. Because the types and magnitudes of adverse impacts to ESA-listed species would depend on the proposed site, alternative design, operation, and species and habitats listed when the alternative is implemented, the NRC cannot forecast a particular level of impact for this alternative.

4.8.7 Purchased Power

Because the purchased power alternative would include a mixture of coal, natural gas, nuclear, and wind across many different sites in the ROI, the special status species and habitats affected by the action would be different from those considered under the proposed action. This alternative would be more likely to intensify already-existing effects at existing power generating facilities than create wholly new effects on protected species and habitats. Because the types and magnitudes of adverse impacts to ESA-listed species would depend on the proposed sites, plant designs, operation, and species and habitats listed at the various sites when the alternative is implemented, the NRC cannot forecast a particular level of impact for this alternative. As with the other alternatives discussed previously, the facilities themselves, and not the NRC, would be responsible for initiating section 7 consultation if listed species or habitats might be adversely affected under this alternative. The NRC cannot forecast a particular level of impact for this alternative.

4.9 Historic and Cultural Resources

This section describes the potential impacts of the proposed action (license renewal) and alternatives to the proposed action on historic and cultural resources.

4.9.1 Proposed Action

The historic and cultural resource issue applicable to Byron during the license renewal term is listed in Table 4–11. Section 3.9 of this SEIS describes the historic and cultural resources that have the potential to be affected by the proposed action.

Table 4–11. Historic and Cultural Resources

Issue	GEIS Section	Category
Historic and Cultural Resources	4.7.1	2

Source: Table B–1 in Appendix B, Subpart A, to 10 CFR Part 51

The National Historic Preservation Act of 1966, as amended (NHPA), requires Federal agencies to consider the effects of their undertakings on historic properties, and renewing the operating license of a nuclear power plant is an undertaking that could potentially affect historic properties. Historic properties are defined as resources eligible for listing in the National Register of Historic Places (NRHP). The criteria for eligibility are listed in 36 CFR Part 60.4 and include (1) association with significant events in history; (2) association with the lives of persons significant in the past; (3) embodiment of distinctive characteristics of type, period, or construction; and (4) sites or places that have yielded, or are likely to yield, important information.

The historic preservation review process (Section 106 of the NHPA) is outlined in regulations issued by the Advisory Council on Historic Preservation (ACHP) in 36 CFR Part 800.

In accordance with the provisions of the NHPA, the NRC is required to make a reasonable effort to identify historic properties included in or eligible for inclusion in the NRHP in the area of potential effect (APE). The APE for a license renewal action is the area at the power plant site, the transmission lines up to the first substation and immediate environs that may be affected by the license renewal decision, and land-disturbing activities associated with continued reactor operations. For Byron, the first substation is located on site at the 345-kV Byron Station switchyard (Exelon 2013b).

If historic properties are present within the APE, the NRC is required to contact the State Historic Preservation Office, assess the potential impact, and resolve any possible adverse effects of the undertaking (license renewal) on historic properties. In addition, the NRC is required to notify the State Historic Preservation Office if historic properties would not be affected by license renewal or if no historic properties are present. The State Historic Preservation Office is part of the Illinois Historic Preservation Agency (IHPA).

<u>Consultation</u>

In accordance with 36 CFR 800.8(c), on August 9, 2013, the NRC initiated consultations on the proposed action by writing to the ACHP and IHPA (NRC 2013d, 2013e). Also on August 9, 2013, the NRC initiated consultation with the following 14 Federally recognized tribes (NRC 2013f) (see Appendix D for a copy of these letters):

- Ho-Chunk Nation;
- Miami Tribe of Oklahoma;
- Peoria Tribe of Indians of Oklahoma;
- Citizen Potawatomi Nation;
- Sac and Fox Tribe of the Mississippi in Iowa/Meskwaki Nation;
- Sac and Fox Nation of Missouri in Kansas and Nebraska;
- Sac and Fox Nation;

- Pokagon Band of Potawatomi;
- Forest County Potawatomi;
- Hannahville Indian Community, Band of Potawatomi;
- Prairie Band Potawatomi Nation;
- Winnebago Tribe of Nebraska;
- Kickapoo Tribe in Kansas; and
- Kickapoo Tribe of Oklahoma.

By letter, the NRC provided information about the proposed action, defined the APE, and indicated that the NHPA review would be integrated with the NEPA process, according to 36 CFR 800.8. NRC invited participation in the identification and possible decisions concerning historic properties and also invited participation in the scoping process. The NRC received no scoping comments from any of the tribes contacted. In September 2013, the NRC received a determination from the IHPA stating no objection to the undertaking and that no historic properties would be affected (IHPA 2013) (see Appendix D).

Exelon currently has no planned physical changes or license renewal-related ground-disturbing activities at the Byron site (Exelon 2013b). As described in Section 3.9, there are no historic properties or known NRHP-eligible historic or cultural resources located within the Byron APE. However, non-NRHP eligible cultural resources are present within the APE and approximately 400 ac of the Byron site is undisturbed land (Exelon 2013b). Furthermore, the Illinois Inventory of Archaeological Sites has identified the area along the banks of the Rock River in the Byron site as having archaeological resource potential (ISM 2014). As a result, Exelon established a draft Cultural Resource Management Plan (CRMP) to ensure historic and cultural resources are considered prior to any ground-disturbing activities at Byron. The CRMP identifies locations of known historic and cultural resource sites and previously disturbed areas within Byron property. The CRMP also instructs Exelon staff on how to evaluate land-disturbing activity for possible impacts to historic and cultural resources (Exelon 2013b). If historic or cultural resources are inadvertently discovered during operational activities, the CRMP directs Exelon staff to stop work, protect exposed resources, and contact Exelon environmental personnel to take appropriate action (Exelon 2013b). Supplemental cultural resource surveys may be performed on the affected areas based on consultation with the State Historic Preservation Office. Day-to-day maintenance of the Byron site follows guidelines based on the type of land use, and less developed areas are not regularly landscaped unless specially requested. Land known to contain historic and cultural resources on the Byron site is not maintained any differently than other landscapes within the property (Exelon 2013b).

Based on (1) there being currently no NRHP-eligible historic properties in the APE, (2) tribal input, (3) Exelon's draft CRMP, (4) the fact that no license renewal-related physical changes or ground-disturbing activities would occur, (5) IHPA input, and (6) cultural resource assessment, license renewal would not affect any known historic properties (36 CFR Section 800.4(d)(1)). Exelon could reduce the risk of potential impacts to historic and cultural resources located on or near the Byron site by finalizing their draft CRMP, with input from the State Historic Preservation Office, and by providing training on cultural resources for Exelon staff engaged in planning and executing ground-disturbing activities.

4.9.2 No-Action Alternative

Not renewing the operating licenses and terminating reactor operations would have no effect on historic properties and cultural resources on or in the immediate vicinity of Byron. A separate environmental review would be conducted to determine the impacts of decommissioning activities on historic properties and cultural resources.

4.9.3 New Nuclear Alternative

Any land areas potentially affected by the construction and operation of a new nuclear alternative power plant would need to be surveyed to identify and record historic and archaeological cultural resources. An inventory of a previously disturbed former plant industrial site may still be necessary if the site has not been previously surveyed or to verify the level of previous disturbance and to evaluate the potential for intact subsurface cultural resources to be present. All potentially affected land areas would need to be surveyed, including land required for new roads, transmission corridors, other right-of-ways (ROWs). Any cultural resources found during these surveys would need to be evaluated for eligibility for listing on the NRHP. Mitigation of adverse effects would need to be considered if eligible resources were encountered. Areas with the greatest sensitivity and most significant cultural resources should be avoided. Visual impacts on significant cultural resources, such as the viewsheds of historic properties near the proposed power plant site, should also be assessed and evaluated.

The potential for impacts to historic and cultural resources from the construction and operation of a new nuclear power plant would vary greatly depending on the location of the site. Cooling towers could impact historic property viewsheds. However, given that the preference is to construct a new nuclear power plant at a previously disturbed former power plant site, avoidance of undisturbed land could further reduce potential impacts to historic and cultural resources. Therefore, the impacts on historic and cultural resources from the construction and operation of a new nuclear power plant would be SMALL.

4.9.4 IGCC Alternative

Any areas potentially affected by the construction and operation of an IGCC power plant would need to be surveyed to identify and record historic and cultural resources. If the IGCC power plant is constructed at the existing Byron site, previously disturbed areas known to not contain historic and cultural resources could be used. If the power plant is sited on the approximately 400 ac (162 ha) of undisturbed land on the Byron site, a survey and inventory of potential historic and cultural resources would need to be performed. If the IGCC power plant is sited at an existing power plant site other than Byron, a cultural resource survey may still be necessary if the site has not been previously surveyed or to verify the level of disturbance and evaluate the potential for intact subsurface resources. Any resources found in these surveys would need to be evaluated for eligibility on the NRHP, and mitigation of adverse effects would need to be addressed if eligible resources were encountered. Areas with the greatest sensitivity should be avoided. Visual impacts on significant cultural resources, such as the viewsheds of historic properties near the proposed power plant site, should also be assessed and evaluated.

The potential for impacts on historic and cultural resources from the construction and operation of an IGCC power plant would vary greatly depending on the location of the proposed site. Given that the preference is to use a previously disturbed former power plant site and no major infrastructure upgrades are necessary, avoidance of significant historic and cultural resources should be possible and effectively managed under current laws and regulations. Therefore, the impacts on historic and cultural resources from the IGCC alternative would be SMALL.

4.9.5 NGCC Alternative

Any areas potentially affected by the construction and operation of an NGCC power plant would need to be surveyed to identify and record historic and cultural resources. If the NGCC power plant is constructed at the existing Byron site, previously disturbed areas known to not contain historic and cultural resources could be used. If the power plant is sited on the approximately 400 ac (162 ha) of undisturbed land on the Byron site, a survey and inventory of potential historic and cultural resources would need to be performed. If the NGCC power plant is sited at an existing power plant site other than Byron, a cultural resource survey may still be necessary if the site has not been previously surveyed or to verify the level of disturbance and evaluate the potential for intact subsurface resources. Additionally, plant operators would need to survey all areas associated with the alternative (e.g., a new pipeline, roads, transmission corridors, other ROWs). Any resources found in these surveys would need to be evaluated for eligibility on the NRHP, and mitigation of adverse effects would need to be addressed if eligible resources were encountered. Areas with the greatest sensitivity should be avoided. Visual impacts on significant cultural resources, such as the viewsheds of historic properties near the proposed power plant site, should also be assessed and evaluated.

The potential for impacts on historic and cultural resources from the construction and operation of an NGCC power plant would vary greatly depending on the location of the proposed site. Given that the preference is to use a previously disturbed former power plant site, avoidance of significant historic and cultural resources should be possible and effectively managed under current laws and regulations. However, historic and archaeological resources could potentially be affected, depending on the resource richness of the land required for a new gas pipeline. Therefore, the impacts on historic and cultural resources from the NGCC alternative would be SMALL to MODERATE.

4.9.6 Combination Alternative (NGCC, Wind, Solar)

Areas potentially affected by the construction and operation of an NGCC power plant and wind and solar PV power generating facilities would need to be surveyed to identify and record historic and archaeological resources. Any historic and cultural resources found in these surveys would need to be evaluated for eligibility on the NRHP, and mitigation of adverse effects would need to be addressed if eligible resources were encountered.

Impacts to historic and cultural resources from the NGCC portion of this alternative would be similar to the NGCC alternative in Section 4.9.5. The potential for impacts on historic and cultural resources from the wind portion of this alternative would vary greatly, depending on the location of the proposed sites. Areas with the greatest cultural sensitivity could be avoided or effectively managed under current laws and regulations. Construction of wind farms and their support infrastructure could impact historic and cultural resources because of earthmoving activities (e.g., grading and digging) and the aesthetic changes to the viewshed of historic properties located nearby. The impacts of the construction of a new solar PV alternative on historic and cultural resources would vary depending on the form of the solar capacity installed. Rooftop installations minimize land disturbance and the modifications necessary to the transmission system, thereby minimizing impacts to historic and cultural resources. Land-based installations would be larger than rooftop installations and will require some degree of land disturbance for installation purposes, potentially causing greater impacts to historic and cultural resources. Aesthetic changes caused by the installation of both forms could have a noticeable effect on the viewshed of nearby historic properties. Using previously disturbed sites for land-based installations and colocating any new transmission lines with existing ROWs could minimize impacts to historic and cultural resources. Areas with the greatest amount of significant resources could be avoided or effectively managed under current laws and regulations. Therefore, depending on the resource richness of the sites chosen for the NGCC, wind, and solar PV alternative, the impacts on historic and cultural resources could range from SMALL to LARGE.

4.9.7 Purchased Power

No direct impacts on historic and cultural resources are expected from purchased power. If new transmission lines were needed to convey power to the PJM Interconnection area, surveys similar to those discussed in Section 4.9.3 would need to be performed. However, transmission lines would likely be colocated with existing ROWs minimizing any impacts to historic and cultural resources.

Indirectly, construction of new nuclear, coal-fired, and natural gas-fired plants, or wind energy projects, and any new transmission lines to support increased demand in the purchased power alternative could affect historic and cultural resources. Any areas potentially affected by construction would need to be surveyed to identify and record historic and cultural resources. Resources found in these surveys would need to be evaluated for eligibility on the NRHP, and mitigation of adverse effects would need to be addressed if eligible resources were encountered. Plant operators would need to survey all areas associated with operation of the alternative (e.g., roads, transmission corridors, other ROWs). The potential for impacts on historic and cultural resources would vary greatly depending on the location of the proposed sites; however, using previously disturbed sites could greatly minimize impacts to historic and cultural resources. Areas with the greatest sensitivity could be avoided or effectively managed under current laws and regulations. Therefore, depending on the resource richness of the sites chosen, the impacts on historic and cultural resources could range from SMALL to LARGE.

4.10 Socioeconomics

In license renewal environmental reviews, the NRC considers the environmental consequences of the proposed action (i.e., continued reactor operations), the no-action alternative (i.e., not renewing the operating license), and the environmental consequences of various alternatives for replacing the nuclear power plant's generating capacity. In plant-specific environmental reviews, the NRC staff compares the environmental impacts of license renewal with those of the no-action alternative and replacement power alternatives to determine whether the adverse environmental impacts of license renewal are great enough to deny the option of license renewal for energy-planning decisionmakers.

4.10.1 Proposed Action

The Category 1 (generic) socioeconomic NEPA issues in 10 CFR Part 51, Appendix B to Subpart A, Table B-1, applicable to the license renewal of Byron are shown in Table 4–12. No Category 2 socioeconomic NEPA issues were identified during the review conducted for the 2013 GEIS revision (NRC 2013a). Socioeconomic effects of ongoing reactor operations at Byron have become well-established as regional socioeconomic conditions have adjusted to the presence of the nuclear power plant. These conditions are described in Section 3.10. Any changes in employment and tax payments caused by license renewal and any associated refurbishment activities could have a direct and indirect impact on community services and housing demand, as well as traffic volumes in the communities around a nuclear power plant.

Table 4–12. Socioeconomic NEPA Issues Affected by License Renewal

Issue	GEIS Section	Category
Employment and income, recreation, and tourism	4.8.1.1	1
Tax revenues	4.8.1.2	1
Community services and education	4.8.1.3	1
Population and housing	4.8.1.4	1
Transportation	4.8.1.5	1

Source: Table B-1 in Appendix B, Subpart A, to 10 CFR Part 51

The supplemental site-specific socioeconomic impact analysis for the license renewal of Byron included a review of Exelon's ER (Exelon 2013a), scoping comments, other information records, and a data-gathering site visit to Byron. NRC staff did not identify any new and significant information during the review that would result in impacts that would exceed the predicted socioeconomic impacts evaluated in the GEIS, and no additional socioeconomic NEPA issues were identified beyond those listed in Table B-1.

In addition, Exelon indicated in its ER (Exelon 2013a) that it has no plans to add non-outage workers during the license renewal term and that increased maintenance and inspection activities could be managed using the current workforce. Consequently, people living in the vicinity of Byron are not likely to experience any changes in socioeconomic conditions during the license renewal term beyond what is currently being experienced. Therefore, the impact of continued reactor operations during the license renewal term would not exceed the socioeconomic impacts predicted in the GEIS. For these issues, the GEIS predicted that the impacts would be SMALL for all nuclear plants.

4.10.2 No-Action Alternative

4.10.2.1 Socioeconomics

Not renewing the operating licenses and terminating reactor operations would have a noticeable impact on socioeconomic conditions in the communities located near Byron. The loss of jobs and income would have an immediate socioeconomic impact. Some, but not all, of the approximately 890 employees (870 Exelon and 20 long-term contract employees) would begin to leave after reactor operations are terminated; and overall tax revenue generated by plant operations would be reduced (Exelon 2013a). Exelon pays annual property taxes to a number of taxing entities within, and including, Ogle County. The Ogle County Treasurer collects Byron's property tax payment and disperses it to the various taxing entities to partially fund their respective operating budgets. The taxing entities to which Exelon pays taxes include, but are not limited to, the Byron Forest Preserve, the Oregon Park District, the Rock Valley Community College 511, the Byron Unit 226 School District, the Byron Fire District, the Byron Library District, Ogle County, and Rockvale Township (Exelon 2013a). The loss of tax revenue could reduce or eliminate some public and educational services. Indirect employment and income generated by plant operations would also be reduced.

Former Byron workers and their families could leave in search of employment elsewhere. The increase in available housing along with decreased demand could cause housing prices to fall. Since the majority of employees reside in Ogle, Lee, and Winnebago Counties, socioeconomic impacts from the termination of reactor operations would be concentrated in these counties, with a corresponding reduction in purchasing activity and tax revenue in the regional economy.

Income and revenue losses from the termination of reactor operations at Byron would directly affect Ogle County and nearby communities most reliant on income from power plant operations. The impact of the job loss, however, may not be as noticeable in local communities given the amount of time required for decommissioning. The socioeconomic impacts from the termination of nuclear plant operations (which may not entirely cease until after decommissioning) would, depending on the jurisdiction, range from SMALL to LARGE.

4.10.2.2 Transportation

Traffic congestion caused by commuting workers and truck deliveries on roads in the vicinity of Byron would be reduced after power plant shutdown. Most of the reduction in traffic volume would be associated with the loss of jobs. The number of truck deliveries to Byron would be reduced until decommissioning. Traffic-related transportation impacts would be SMALL as a result of the shutdown of the nuclear power plant.

4.10.3 New Nuclear Alternative

4.10.3.1 Socioeconomics

Socioeconomic impacts are defined in terms of changes to the demographic and economic characteristics and social conditions of a region. For example, the number of jobs created by the construction and operation of a power plant could affect regional employment, income, and expenditures.

Two types of jobs would be created by this alternative: (1) construction jobs, which are transient, short in duration, and less likely to have a long-term socioeconomic impact, and (2) power plant operations jobs, which have the greater potential for permanent, long-term socioeconomic impacts. Workforce requirements for the construction and operation of a new nuclear power plant were evaluated to measure their possible effects on current socioeconomic conditions.

Exelon estimated the construction workforce would peak at 3,500 workers (NRC 2008). The relative economic effect of this many workers on the local economy and tax base would vary with the greatest impacts occurring in the communities where the majority of construction workers would reside and spend their income. As a result, local communities could experience a short-term economic “boom” from increased tax revenue and income generated by construction expenditures and the increased demand for temporary (rental) housing and public as well as commercial services.

After construction, local communities could experience a return to preconstruction economic conditions. Based on this information and given the number of workers, socioeconomic impacts during construction in communities near an existing nuclear power plant or retired coal site could range from MODERATE to LARGE.

An estimated 812 workers would be required during nuclear power plant operations (NRC 2008). Some Byron operations workers could transfer to the new nuclear power plant. Local communities near the new nuclear power plant would experience the economic benefits from increased tax revenue and income generated by operational expenditures and demand for housing and public as well as commercial services. The amount of property tax payments under the new nuclear alternative may also increase if additional land is required to support this alternative.

This alternative would also result in a loss of approximately 890 relatively high-paying jobs at Byron and a corresponding reduction in purchasing activity and revenue contributions to the regional economy. Should Byron cease operations, there would be an immediate socioeconomic impact to local communities and businesses from the loss of jobs (some, but not all, of the 890 employees would begin to leave), and tax payments may be reduced. In addition, the housing market could experience increased vacancies and decreased prices if operations workers and their families move out of the region. The impact of the job loss, however, may not be noticeable in local communities given the amount of time required for decommissioning of the existing Byron facilities. Based on this information and given the number of operations workers, socioeconomic impacts during nuclear power plant operations on local communities could range from SMALL to MODERATE.

4.10.3.2 Transportation

Transportation impacts associated with construction and operation of a new nuclear power plant would consist of commuting workers and truck deliveries of construction materials to the power plant site. During periods of peak construction activity, up to 3,500 workers could be commuting daily to the construction site (NRC 2008). Workers commuting to the construction site would arrive via site access roads and the volume of traffic on nearby roads could increase substantially during shift changes. In addition to commuting workers, trucks would be transporting construction materials and equipment to the work site, thereby increasing the amount of traffic on local roads. The increase in vehicular traffic would peak during shift changes, resulting in temporary levels of service impacts and delays at intersections. Materials could also be delivered by rail or barge, depending on the location. Traffic-related transportation impacts during construction would likely range from MODERATE to LARGE.

Traffic-related transportation impacts on local roads would be greatly reduced after the completion of the power plant. Transportation impacts would include daily commuting by the operating workforce, equipment and materials deliveries, and the removal of commercial waste material to offsite disposal or recycling facilities by truck. Traffic on roadways would peak during shift changes, resulting in temporary levels of service impacts and delays at intersections. Overall, at the new nuclear power plant site, transportation impacts would be SMALL to MODERATE during operations.

4.10.4 IGCC Alternative

4.10.4.1 Socioeconomics

As explained in Section 4.10.3, two types of jobs would be created by this alternative: (1) construction jobs, which are transient, short in duration, and less likely to have a long-term socioeconomic impact, and (2) power plant operations jobs, which have the greater potential for permanent, long-term socioeconomic impacts. Workforce requirements for the construction and operation of the IGCC alternative were evaluated to measure their possible effects on current socioeconomic conditions.

The construction workforce could peak at 4,600 workers (DOE 2010a), if the four new units are constructed at four different locations. Fewer construction workers would be required if all units are constructed at Byron or a single existing power plant site. The relative economic effect of this many workers on the local economy and tax base would vary with the greatest impacts occurring in the communities where the majority of construction workers would reside and spend their income. As a result, local communities could experience a short-term economic "boom" from increased tax revenue and income generated by construction expenditures and the increased demand for temporary (rental) housing and public as well as commercial services.

After construction, local communities could experience a return to preconstruction economic conditions. Based on this information and given the number of workers, socioeconomic impacts during construction in communities near an existing power plant site could range from MODERATE to LARGE.

An estimated 420 workers would be required during power plant operations (DOE 2010a), if the four new units are operated at four different locations. Fewer workers would be required if all four units are operated at Byron or a single existing power plant site. Local communities would experience the economic benefits from increased tax revenue and income generated by operational expenditures and demand for housing and public as well as commercial services. The amount of property tax payments under the IGCC alternative may also increase if additional land is required to support this alternative.

This alternative could also result in a loss of approximately 890 relatively high-paying jobs at Byron and a corresponding reduction in purchasing activity and revenue contributions to the regional economy. Should Byron cease operations, there would be an immediate socioeconomic impact to local communities and businesses from the loss of jobs (some, but not all, of the 890 employees would begin to leave), and tax payments may be reduced. In addition, the housing market could experience increased vacancies and decreased prices if operations workers and their families move out of the region. The impact of the job loss, however, may not be noticeable in local communities given the amount of time required for decommissioning of the existing Byron facilities. Based on this information and given the number of operations workers, socioeconomic impacts during IGCC power plant operations on local communities could range from SMALL to MODERATE.

4.10.4.2 Transportation

Transportation impacts associated with construction and operation of the four-unit IGCC power plants would consist of commuting workers and truck deliveries of construction materials to Byron or the existing power plant site. During periods of peak construction activity, up to 4,600 workers could be commuting daily to one or more construction sites. As previously discussed, fewer workers would be commuting if all four units are constructed at Byron or a single existing power plant site. Workers commuting to the construction site would arrive via site access roads and the volume of traffic on nearby roads could increase substantially during shift changes. In addition to commuting workers, trucks would be transporting construction materials and equipment to the work site, thereby increasing the amount of traffic on local roads. The increase in vehicular traffic would peak during shift changes, resulting in temporary levels of service impacts and delays at intersections. Materials could also be delivered by rail or barge, depending on location. Traffic-related transportation impacts during construction would likely range from MODERATE to LARGE.

Traffic-related transportation impacts on local roads would be greatly reduced after the completion of the power plant. The estimated maximum number of operations workers commuting daily to one or more power plant sites could be 420 (DOE 2010a). Fewer workers would be commuting if all four units are operated at the same site. Frequent coal and limestone deliveries and ash removal by rail would add to the overall transportation impact. The increase in traffic on roadways would peak during shift changes, resulting in temporary levels of service impacts and delays at intersections. Onsite coal storage would make it possible to receive several trains per day at a site with rail access. If the IGCC power plant is located on navigable waters, coal and other materials could be delivered by barge. Coal and limestone delivery and ash removal via rail would cause levels of service impacts due to delays at railroad crossings. Overall, transportation impacts would be SMALL to MODERATE during IGCC power plant operations.

4.10.5 NGCC Alternative

4.10.5.1 Socioeconomics

As explained in Section 4.10.3, two types of jobs would be created by this alternative: (1) construction jobs, which are transient, short in duration, and less likely to have a long-term socioeconomic impact, and (2) power plant operations jobs, which have the greater potential for permanent, long-term socioeconomic impacts. Workforce requirements for the construction and operation of the NGCC alternative were evaluated to measure their possible effects on current socioeconomic conditions.

The construction workforce would peak at 1,783 workers (Exelon 2013a). The relative economic effect of this many workers on the local economy and tax base would vary, with the greatest impacts occurring in the communities where the majority of construction workers would reside and spend their income. As a result, local communities near Byron or another existing power plant site could experience a short-term economic "boom" from increased tax revenue and income generated by construction expenditures and the increased demand for temporary (rental) housing and public as well as commercial services.

After construction, local communities could experience a return to preconstruction economic conditions. Based on this information and given the number of workers, socioeconomic impacts during construction in communities near Byron or another existing power plant site could range from MODERATE to LARGE.

An estimated 94 workers would be required during power plant operations (Exelon 2013a). Local communities would experience the economic benefits from increased tax revenue and income generated by operational expenditures and demand for housing and public as well as commercial services. The amount of property tax payments under the NGCC alternative may also increase if additional land is required to support this alternative.

This alternative would also result in a loss of approximately 890 relatively high-paying jobs at Byron and a corresponding reduction in purchasing activity and revenue contributions to the regional economy. Should Byron cease operations, there would be an immediate socioeconomic impact to local communities and businesses from the loss of jobs (some, but not all, of the 890 employees would begin to leave), and tax payments may be reduced. In addition, the housing market could experience increased vacancies and decreased prices if operations workers and their families move out of the region. The impact of the job loss, however, may not be noticeable in local communities given the amount of time required for decommissioning of the existing Byron Station facilities. Based on this information and given the number of operations workers, socioeconomic impacts during NGCC power plant operations on local communities could range from SMALL to MODERATE.

4.10.5.2 Transportation

Transportation impacts associated with construction and operation of a five-unit NGCC power plant would consist of commuting workers and truck deliveries of construction materials to the power plant site.

During periods of peak construction activity, up to 1,783 workers could be commuting daily to the construction site. Workers commuting to the construction site would arrive via site access roads and the volume of traffic on nearby roads could increase substantially during shift changes. In addition to commuting workers, trucks would be transporting construction materials and equipment to the work site, thus increasing the amount of traffic on local roads. The increase in vehicular traffic would peak during shift changes, resulting in temporary levels of service impacts and delays at intersections. Pipeline construction and modification of existing natural gas pipeline systems could also have a temporary impact. Materials also could be delivered by barge or rail, depending on location. Traffic-related transportation impacts during construction would likely range from MODERATE to LARGE.

Traffic-related transportation impacts would be greatly reduced after completing the installation of the NGCC alternative. Transportation impacts would include daily commuting by the operating workforce, equipment and materials deliveries, and the removal of commercial waste material to offsite disposal or recycling facilities by truck. The operations workforce of 94 workers would likely not be noticeable relative to total traffic volumes on local roadways. Since fuel is transported by pipeline, the transportation infrastructure would experience little to no increased traffic from plant operations. Overall, given the relatively small operations workforce estimate of 94 workers, transportation impacts would be SMALL during power plant operations.

4.10.6 Combination Alternative (NGCC, Wind, Solar)

4.10.6.1 Socioeconomics

As explained in Section 4.10.3, two types of jobs would be created by this alternative: (1) construction jobs, which are transient, short in duration, and less likely to have a long-term socioeconomic impact, and (2) operations jobs, which have the greater potential for permanent, long-term socioeconomic impacts. Workforce requirements for the construction and operation of the NGCC, wind, and solar generation components of this combination alternative were evaluated to estimate their possible effects on current socioeconomic conditions.

Fewer workers would be required to construct the single NGCC unit at an existing power plant site than the full-power NGCC alternative. Installation of an estimated 3,376 wind turbines would likely be done in stages and could employ up to 931 construction workers (DOE 2010b). Additional workers would be required to install solar PV systems on existing buildings or structures at already-developed residential, commercial, or industrial sites. Similar to the wind farms, installation would likely be done in stages and could employ up to 600 construction workers (DOE 2010b).

Conversely, a small number of operations workers would be needed to operate the single NGCC unit, and additional small numbers of workers would be required to maintain the wind farms and PV systems. Local communities could experience the economic benefits from increased tax revenue and income generated by operational expenditures and demand for housing and public as well as commercial services. The amount of property tax payments under the wind and solar PV components may also increase if additional land is required to support this combination alternative.

This combination alternative would also result in a loss of approximately 890 relatively high-paying jobs at Byron and a corresponding reduction in purchasing activity, tax payments, and revenue contributions would occur in the surrounding regional economy. Should Byron cease operations, there would be an immediate socioeconomic impact to local communities and businesses from the loss of jobs (some, but not all, of the 890 employees would begin to leave), and tax payments may be reduced. In addition, the housing market could experience increased vacancies and decreased prices if operations workers and their families move out of the region. The impact of the job loss, however, may not be noticeable in local communities given the amount of time required for decommissioning of the existing Byron Station facilities. Based on this information and given the relatively small numbers of construction and operations workers, socioeconomic impacts during construction and operations on local communities would be SMALL.

4.10.6.2 Transportation

Transportation impacts during the construction and operation of the NGCC unit as well as the wind and solar components of this combination alternative would be less than the impacts for any of the previous alternatives discussed. This is because the construction workforce for each component and the volume of materials and equipment needing to be transported to the respective construction site would be smaller than for any one of the individual replacement power alternatives. In other words, the transportation impacts would not be concentrated as in the other alternatives, but spread out over a wider area.

Workers commuting to the construction site would arrive via site access roads and the volume of traffic on nearby roads could increase during shift changes. In addition to commuting workers, trucks would be transporting construction materials and equipment to the work site, thereby increasing the amount of traffic on local roads. The increase in vehicular traffic would peak during shift changes, resulting in temporary levels of service impacts and delays at intersections. Transporting heavy and oversized components on local roads could have a noticeable impact over a large area. Some components and materials could also be delivered by rail or barge, depending on location. Traffic-related transportation impacts during construction could range from SMALL to MODERATE at the NGCC power plant, wind farms and solar installations, depending on current road capacities and average daily traffic volumes.

During operations, transportation impacts would be less noticeable during shift changes and maintenance activities. Given the small numbers of operations workers, the levels of service traffic impacts on local roads from NGCC, wind farm, and solar PV operations would be SMALL.

4.10.7 Purchased Power

4.10.7.1 Socioeconomics

Purchased power from existing power generating facilities would not have any socioeconomic impact, because there would be no change in power plant operations or workforce. If the amount of purchased power exceeds the available supply, new electrical power generating facilities would be needed. Construction and operation of a new electrical power generating facility to supply purchased power could cause noticeable socioeconomic impacts in the communities located near the new facility. The intensity of the impact would depend on the number of workers required to build and operate the new electrical power generating facility and the amount of increased demand for housing and public services.

Whether or not there would be a socioeconomic impact would depend on whether a new electrical power generating facility was needed to supply purchased power. If a new power generating facility is needed, socioeconomic impacts would range anywhere from SMALL to LARGE.

4.10.7.2 Transportation

Similarly, purchased power from existing power generating facilities would also not have any transportation impact, because there would be no change in power plant operations or workforce. Construction and operation of a new electrical power generating facility could cause noticeable transportation impacts depending on the number of workers and truck deliveries required to build and operate the new electrical power generating facility. Traffic volumes could increase noticeably on local roads during shift changes.

Whether or not there would be a transportation impact would depend on whether a new electrical power generating facility was needed to supply purchased power. If a new power generating facility is needed, transportation impacts would range anywhere from SMALL to LARGE.

4.11 Human Health

This section describes the potential impacts of the proposed action (license renewal) and alternatives to the proposed action on human health resources.

4.11.1 Proposed Action

The human health issues applicable to Byron are discussed below and are listed in Table 4–13 for Category 1, Category 2, and uncategorized issues. Table B-1 of Appendix B to Subpart A of 10 CFR Part 51 contains more information on these issues.

Table 4–13. Human Health Issues

Issue	GEIS Section	Category
Radiation exposures to the public	4.9.1.1.1	1
Radiation exposures to plant workers	4.9.1.1.1	1
Human health impact from chemicals	4.9.1.1.2	1
Microbiological hazards to the public (plants with cooling ponds or canals or cooling towers that discharge to a river)	4.9.1.1.3	2
Microbiological hazards to plant workers	4.9.1.1.3	1
Chronic effects of electromagnetic fields (EMFs)[a]	4.9.1.1.4	N/A[b]
Physical occupational hazards	4.9.1.1.5	1
Electric shock hazards[a]	4.9.1.1.5	2

[a] This issue applies only to the inscope portion of electric power transmission lines, which are defined as transmission lines that connect the nuclear power plant to the substation where electricity is fed into the regional power distribution system and transmission lines that supply power to the nuclear plant from the grid.

[b] N/A (not applicable) The categorization and impact finding definition does not apply to this issue

Source: Table B-1 in Appendix B, Subpart A, to 10 CFR Part 51 (NRC 2013a)

4.11.1.1 Normal Operating Conditions

<u>Generic Human Health Issues (Category 1)</u>

The NRC staff did not identify any new and significant information during its review of Exelon's ER (Exelon 2013a), the site audit, or the scoping process for the Category 1 issues listed in Table 4–13. Therefore, there are no impacts related to these issues beyond those discussed in the GEIS. For these Category 1 issues, the GEIS concluded that the impacts are SMALL.

Chronic Effects of Electromagnetic Fields (EMFs)

In the GEIS (NRC 2013a), the chronic effects of 60-Hz electromagnetic fields (EMFs) from power lines were not designated as Category 1 or 2 and will not be until a scientific consensus is reached on the health implications of these fields.

The potential for chronic effects from these fields continues to be studied and is not known at this time. The National Institute of Environmental Health Sciences (NIEHS) directs related research through the U.S. Department of Energy (DOE).

The report by NIEHS (NIEHS 1999) contains the following conclusion:

> The NIEHS concludes that ELF-EMF (extremely low frequency-electromagnetic field) exposure cannot be recognized as entirely safe because of weak scientific evidence that exposure may pose a leukemia hazard. In our opinion, this finding is insufficient to warrant aggressive regulatory concern. However, because virtually everyone in the United States uses electricity and therefore is routinely exposed to ELF-EMF, passive regulatory action is warranted such as continued emphasis on educating both the public and the regulated community on means aimed at reducing exposures. The NIEHS does not believe that other cancers or non-cancer health outcomes provide sufficient evidence of a risk to currently warrant concern.

This statement is not sufficient to cause the NRC staff to change its position with respect to the chronic effects of EMFs. The NRC staff considers the GEIS finding of “UNCERTAIN” still appropriate and will continue to follow developments on this issue.

<u>Site-Specific Human Health Issues (Category 2)</u>

Microbiological Hazards to the Public

In the GEIS (NRC 2013a), the NRC staff determined that effects of thermophilic microorganisms on the public for plants using cooling ponds, lakes, or canals or cooling towers that discharge to a river is a Category 2 issue (see Table 4–12) that requires site-specific evaluation during each license renewal review.

In order to determine whether the continued operations of Byron could promote increased growth of thermophilic microorganisms, and thus have an adverse effect on the public, the NRC staff considered several factors: the thermophilic microorganisms of concern, Byron’s thermal effluent characteristics, Exelon’s chlorination procedures, recreational Rock River use in the vicinity of Byron, and input from the Illinois Department of Public Health (IDPH).

Thermophilic Microorganisms of Concern

Section 3.11.3 describes the thermophilic microorganisms that the GEIS identified to be of potential concern at nuclear power plants and summarizes data from the Centers for Disease Control and Prevention (CDC) on the prevalence of waterborne diseases associated with these microorganisms that have been linked to recreational water use in the past 10 available data years (1999 through 2008). CDC data indicate that no outbreaks or cases of waterborne *Salmonella* or *Pseudomonas aeruginosa* infection from recreational waters have occurred in the United States during this timeframe. *Shigella* and *Naegleria fowleri* infections linked to exposure in recreational waters were rarely reported, and none of the reported cases occurred in Illinois. Public exposure to aerosolized *Legionella* from nuclear plant operations is generally not a concern because such exposure would be confined to a small area of the site to which the public would not have access. Based on the information presented in Section 3.11.3, the thermophilic organisms most likely to be of potential concern at Byron are *Shigella* and *N. fowleri*.

Byron Thermal Effluent Characteristics

Byron discharges cooling tower blowdown to the Rock River at an average rate of 900 L/s (14,000 gpm) (Exelon 2013a). Sections 3.1.3 and 3.5.1 describe the cooling system and surface water characteristics, respectively.

The Illinois Administrative Code (IAC) Title 35, *Environmental Protection*, Section 302, "Water Quality Standards," stipulates that for thermal effluents, the maximum temperature rise shall not exceed 2.8 °C (5 °F) above natural receiving water body temperatures and that the water temperature at representative locations in the main river shall at no time exceed 33.7 °C (93 °F) from April through November and 17.7 °C (63 °F) in other months (35 IAC 302.211). Special Condition 12 of Byron's NPDES permit (IEPA 2011) requires Exelon to perform daily calculations to demonstrate compliance with the thermal water quality standard during times when Rock River flow is less than 67,944 L/s (1,076,900 gpm) or the temperature difference between the main river temperature and the water quality standard is less than 3 °F (1.6 °C).

In recent years, the highest daily blowdown temperature that Exelon reported was 39.4 °C (103 °F) in July 2012 (Exelon 2013b). This temperature was recorded during drought conditions in Illinois. Previously, the highest temperature had been 36 °C (97 °F) in August 2009 (Exelon 2013a). The July 2012 maximum temperature is below the optimum growth temperature for the microorganisms of concern. At this temperature, *Shigella* could persist but would be unlikely to experience enhanced growth or survival from the thermal addition of cooling tower blowdown to the river. *N. fowleri* prefers much higher temperatures for optimum growth (46 °C (115 °F)). *N. fowleri* has been isolated from thermally altered waters surrounding power plant discharges at temperatures ranging from 35 to 41 °C (95 to 105.8 °F); however, because the IAC normally limits discharge temperatures to 33.7 °C (93 °F), the species is unlikely to be present in the water.

Additionally, the IAC prohibits the area and volume of thermal mixing from being more than 25 percent of the cross-sectional area or volume of stream flow (35 IAC 302.102). The Illinois Environmental Protection Agency (IEPA) has determined that Byron meets this criterion, as stated in Special Condition 3 of Byron's NPDES permit (IEPA 2011). Thus, the IAC's thermal mixing limitations effectively minimize the area and volume over which microorganisms could experience enhanced growth or survival.

Byron Chlorination Procedures

Chlorine is an effective disinfectant for water containing the microorganisms of concern. EPA (1999a) reports that chlorination at concentrations of 1 to 2 milligrams per liter (mg/L) (1 to 2 parts per million (ppm)) in water at a pH of 6.0 to 8.0 can effectively eliminate health hazards caused by bacteria, including *Shigella*. The CDC (2013) reports that chlorine at a concentration of 1 ppm (1 mg/L) added to 77 °F (25 °C) clear water at a pH of 7.5 will reduce the number of viable *Naegleria fowleri* trophozoites by 99.99 percent in 12 minutes.

Exelon chlorinates Rock River water, which is then used in Byron's three cooling and auxiliary water systems. Sodium hypochlorite and sodium bromide at target concentrations of 0.2 and 0.5 ppm are injected into each unit's circulating water system for 2 hours per day per unit during operation. The nonessential service water system is chlorinated by continuously injecting sodium hypochlorite at a concentration of 0.05 to 0.2 ppm. The essential service water (SX) system is also continuously chlorinated with sodium hypochlorite at a concentration of 0.05 to 0.2 ppm. Sodium bisulfate is added to water to eliminate any residual biocide concentration prior to returning water to the Rock River (Exelon 2013b). Although Exelon chlorinates station water at lower concentrations than those indicated by EPA and the CDC as most effectively eliminating the microorganisms of concern, chlorination of the system is likely to prevent some increased growth and survival of microorganisms that might otherwise result from operation of Byron.

Recreational Rock River Use in the Vicinity of Byron

As discussed above, Byron's thermal mixing zone is relatively small. Thus, the highest risk of exposure to elevated levels of thermophilic microorganisms, if present, would likely be within the restricted area. Additionally, the majority of land adjacent to the Rock River in the vicinity of Byron is private and zoned for agricultural uses (OCPZD 2013). Thus, because public access to waters that are thermally affected by Byron operations is limited, exposure of the public to elevated levels of thermophilic microorganisms is unlikely. Additionally, the IAC prohibits mixing "in water adjacent to bathing beaches, bank fishing areas, boat ramps or dockages or any other public access area." Thus, any changes in surrounding land use during the proposed license renewal term would continue to limit public exposure to thermally altered waters.

Illinois Department of Public Health Review

The Environmental Standard Review Plan for license renewal (NRC 2013c) directs NRC staff to consult with the state public health department—in this case, the IDPH—regarding concerns about the potential for waterborne disease outbreaks associated with license renewal. Appendix E of the ER (Exelon 2013a) includes copies of correspondence between Exelon and IDPH regarding this issue. In a January 2013 letter to IDPH, Exelon (2013d) provided a brief assessment that concluded that the license renewal "would not contribute to any increase in adverse effects on public health from exposure to *N. fowleri* or any other thermophilic pathogen in the Rock River." The IDPH (2013) responded in a March 2013 letter and indicated that its staff does not have the expertise necessary to adequately evaluate Exelon's assessment. Accordingly, the NRC did not separately contact the IDPH during its license renewal review.

Conclusion

The thermophilic microorganisms *Shigella* and *Naegleria fowleri* have been linked to waterborne outbreaks in recreational waters within the United States. However, based on these microorganisms' temperature tolerances, *N. fowleri* is unlikely to be present in the vicinity of Byron, and thermal discharges during the proposed license renewal term would only be expected to minimally enhance the survival of *Shigella* spp. Exelon's chlorination procedures and the small thermal mixing zone make the exposure of recreational Rock River users to elevated levels of thermophilic microorganisms unlikely. The NRC staff concludes that the impacts of thermophilic microorganisms on the public are SMALL for Byron license renewal.

<u>Electric shock hazards</u>

Based on the GEIS, the Commission found that electric shock resulting from direct access to energized conductors or from induced charges in metallic structures has not been found to be a problem at most operating plants and generally is not expected to be a problem during the license renewal term. However, a site-specific review is required to determine the significance of the electric shock potential along the portions of the transmission lines that are within the scope of this SEIS.

As discussed in Section 3.11.4, Exelon performed an evaluation of Byron's transmission lines to determine whether the lines conform to the National Electrical Safety Code® (NESC®) criteria for induced electric shock. The Exelon evaluation concluded that none of its transmission lines exceeded the NESC criteria.

Because Byron's transmission lines conform to the NESC criteria during its current license term and is expected to continue to conform to this standard during the license renewal term, the NRC staff concludes that the potential impacts from acute electric shock during the license renewal term would be SMALL.

4.11.1.2 Environmental Impacts of Postulated Accidents

This section describes the environmental impacts from postulated accidents that Byron might experience during the period of extended operation. The term "accident" refers to any unintentional event outside the normal plant operational envelope that results in a release or the potential for release of radioactive materials into the environment. The two classes of postulated accidents listed in Table 4–14 are contained in Table B-1 of Appendix B to Subpart A of 10 CFR Part 51 and are evaluated in detail in the GEIS. These two classes of accidents are DBAs and severe accidents.

Table 4–14. Issues Related to Postulated Accidents

Issue	GEIS Section	Category
DBAs	4.9.1.2	1
Severe accidents	4.9.1.2	2

Source: Table B-1 in Appendix B, Subpart A, to 10 CFR Part 51

<u>Design-Basis Accidents</u>

In order to receive U.S. Nuclear Regulatory Commission (NRC) approval to operate a nuclear power facility, an applicant for an initial operating license must submit a Safety Analysis Report (SAR) as part of its application. The SAR presents the design criteria and design information for the proposed reactor and comprehensive data on the proposed site. The SAR also discusses various hypothetical accident situations and the safety features that are provided to prevent and mitigate accidents. The NRC staff reviews the application to determine whether the plant design meets the Commission's regulations and requirements and includes, in part, the nuclear plant design and its anticipated response to an accident.

Design-basis accidents are those accidents that both the applicant and the NRC staff evaluate to ensure that the plant can withstand normal and abnormal transients and a broad spectrum of postulated accidents, without undue hazard to the health and safety of the public. Many of these postulated accidents are not expected to occur during the life of the plant, but are evaluated to establish the design basis for the preventive and mitigative safety systems of the nuclear power plant. Parts 50 and 100 of 10 CFR describe the acceptance criteria for DBAs.

The environmental impacts of DBAs are evaluated during the initial licensing process, and the ability of the plant to withstand these accidents is demonstrated to be acceptable before issuance of the operating license. The results of these evaluations are found in licensee documentation such as the applicant's final safety analysis report, the safety evaluation report, the final environmental statement (FES), and Section 5.1 of this SEIS. A licensee is required to maintain the acceptable design and performance criteria throughout the life of the plant, including any extended-life operation. The consequences for these events are evaluated for the hypothetical maximum exposed individual; as such, changes in the plant environment will not affect these evaluations. Because of the requirements that continuous acceptability of the consequences and aging management programs be in effect for the period of extended operation, the environmental impacts as calculated for DBAs should not differ significantly from initial licensing assessments over the life of the plant, including the period of extended operation. Accordingly, the design of the plant relative to DBAs during the period of extended operation is considered to remain acceptable, and the environmental impacts of those accidents were not examined further in the GEIS.

The Commission has determined that the environmental impacts of DBAs are of SMALL significance for all plants because the plants were designed to successfully withstand these accidents. Therefore, for the purposes of license renewal, DBAs are designated as a Category 1 issue. The early resolution of the DBAs makes them a part of the current licensing basis of the plant; the current licensing basis of the plant is to be maintained by the licensee under its current license and, therefore, under the provisions of 10 CFR 54.30, is not subject to review under license renewal.

No new and significant information related to DBAs was identified during the review of the Byron ER (Exelon 2013a), site audit, the scoping process, or evaluation of other available information. Therefore, there are no impacts related to these issues beyond those discussed in the GEIS.

Severe Accidents

Severe nuclear accidents are those that are more severe than DBAs because they could result in substantial damage to the reactor core, whether or not there are serious offsite consequences. In the GEIS, the NRC staff assessed the effects of severe accidents during the period of extended operation, using the results of existing analyses and site-specific information to conservatively predict the environmental impacts of severe accidents for each plant during the period of extended operation.

Severe accidents initiated by external phenomena such as tornadoes, floods, earthquakes, fires, and sabotage have not traditionally been discussed in quantitative terms in FESs and were not specifically considered for the Byron site in the GEIS (NRC 1996). However, the GEIS did evaluate existing impact assessments performed by NRC and by the industry at 44 nuclear plants in the United States and concluded that the risk from beyond-design-basis earthquakes at existing nuclear power plants is SMALL. The GEIS for license renewal performed a discretionary analysis of terrorist acts in connection with license renewal, and concluded that the core damage and radiological release from such acts would be no worse than the damage and release expected from internally initiated events. In the GEIS, the Commission concludes that the risk from sabotage and beyond-design-basis earthquakes at existing nuclear power plants is small and additionally, that the risks from other external events are adequately addressed by a generic consideration of internally initiated severe accidents (NRC 1996, 2013a).

Based on information in the GEIS, the staff found the following to be true:

> 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.

The NRC staff identified no new and significant information related to postulated accidents during the review of Exelon's ER for Byron (Exelon 2013a), the site audit, the scoping process, or evaluation of other available information. Therefore, there are no impacts related to these issues beyond those discussed in the GEIS. However, in accordance with 10 CFR 51.53(c)(3)(ii)(L), the staff has reviewed severe accident mitigation alternatives (SAMAs) for Byron. The results of the review are discussed in Section 5.3.

Severe Accident Mitigation Alternatives

Section 51.53(c)(3)(ii)(L) requires that license renewal applicants consider alternatives to mitigate severe accidents if the staff has not previously evaluated SAMAs for the applicant's plant in an environmental impact statement (EIS) or related supplement or in an environmental assessment (EA). The purpose of this consideration is to ensure that plant changes (i.e., hardware, procedures, and training) with the potential for improving severe accident safety performance are identified and evaluated. SAMAs have not been previously considered for Byron; therefore, the remainder of this section addresses those alternatives.

Overview of SAMA Process

This section presents a summary of the SAMA evaluation for Byron conducted by Exelon and the NRC staff's review of that evaluation. The NRC staff performed its review with contract assistance from Pacific Northwest National Laboratory. The NRC staff's review is available in full in Appendix F; the full Exelon SAMA evaluation is available in Exelon's ER.

The SAMA evaluation for Byron was conducted with a four-step approach. In the first step, Exelon quantified the level of risk associated with potential reactor accidents using the plant-specific probabilistic risk assessment (PRA) and other risk models.

In the second step, Exelon examined the major risk contributors and identified possible ways (SAMAs) of reducing that risk. Common ways of reducing risk are changes to components, systems, procedures, and training. Exelon identified 30 potential SAMAs for Byron. Exelon performed an initial screening to determine if any SAMAs could be eliminated because they are not applicable to Byron due to design differences, they have already been implemented at Byron or their intent is achieved by other means, or they have estimated implementation costs that would exceed the dollar value associated with completely eliminating all severe accident risk at Byron related to power generation operations. Three SAMAs were eliminated based on this screening, leaving 27 for further evaluation. One additional candidate SAMA was also further evaluated after accounting for analysis uncertainties.

In the third step, Exelon estimated the benefits and the costs associated with each of the SAMAs. Estimates were made of how much each SAMA could reduce risk. Those estimates were developed in terms of dollars in accordance with NRC guidance for performing regulatory analyses (NRC 1997). The cost of implementing the proposed SAMAs was also estimated.

In the fourth step, the costs and benefits of each of the remaining SAMAs were compared to determine whether the SAMA was cost beneficial, meaning the benefits of the SAMA were greater than the cost (a positive cost benefit). Exelon concluded in its ER that several of the SAMAs evaluated are potentially cost beneficial (Exelon 2013a). In response to NRC staff inquiries regarding estimated benefits for certain SAMAs and lower cost alternatives, two additional potentially cost-beneficial SAMAs were identified (Exelon 2014).

Finally, the potentially cost-beneficial SAMAs are evaluated to determine if they are in the scope of license renewal, (i.e., they are subject to aging management). This evaluation considers whether the structures, systems, and components (SSCs) associated with these SAMAs: (1) perform their intended function without moving parts or without a change in configuration or properties and (2) are subject to replacement based on qualified life or specified time period. The potentially cost-beneficial SAMAs identified for Byron do not relate to adequately managing the effects of aging during the period of extended operation; therefore, they need not be implemented as part of license renewal in accordance with 10 CFR Part 54, "Requirements for renewal of operating licenses for nuclear power plants." Byron's SAMA analyses and the NRC's review are discussed in more detail below.

Estimate of Risk

Exelon submitted an assessment of SAMAs for Byron as part of its ER (Exelon 2013). This assessment was based on the most recent Byron PRA available at that time, a plant-specific offsite consequence analysis performed using the MELCOR Accident Consequence Code System 2 computer program, and insights from the Byron Individual Plant Examination (IPE)

(ComEd 1994, 1997) and Individual Plant Examination of External Events (IPEEE) (ComEd 1996).

The scope of the Level 1 PRA model includes both internal events and a limited fire PRA. The fire PRA is not fully integrated with the most recent internal events model and is an interim implementation of NUREG–6850 (EPRI and NRC 2005). Hence, Exelon performed a separate assessment of the risk (and risk reduction) for internal and fire events.

The baseline core damage frequency (CDF) for the purpose of the SAMA evaluation is approximately 4.0×10^{-5} per year for Unit 1 and 3.8×10^{-5} per year for Unit 2 for internal events (including internal flooding events). The total fire CDF for Unit 1 is approximately 5.4×10^{-5} per year. The Unit 2 fire CDF was not reported or used since the Unit 2 fire model had not been developed to the same degree as the Unit 1 model. Exelon accounted for the potential risk reduction benefits associated with internal events by quantifying the benefits using the internal events model. For internal event-related SAMAs, Exelon accounted for the potential risk reduction benefits associated with external events (e.g., seismic and fire events) by multiplying the estimated benefits for internal events by a factor of 2.6. For fire-related SAMAs, Exelon separately estimated the risk reduction benefits using the fire risk model. The breakdown of CDF by initiating event for Byron is provided in Table 4–15 for internal events.

Table 4–15. Byron Core Damage Frequency for Internal Events

Initiating Event	Unit 1 CDF (per year)	Unit 1 Percent CDF Contribution	Unit 2 CDF (per year)	Unit 2 Percent CDF Contribution
Loss of Essential Service Water (SX)	1.8×10^{-5}	46	1.7×10^{-5}	45
Loss of Component Cooling Water (CCW)	8.3×10^{-6}	21	8.1×10^{-6}	21
Internal Flooding	5.6×10^{-6}	14	5.8×10^{-6}	15
Loss of Auxiliary Power (AP)	2.4×10^{-6}	6	1.8×10^{-6}	5
Small Loss-of-Coolant Accident (LOCA)	1.6×10^{-6}	4	1.5×10^{-6}	4
Other Initiating Events	1.6×10^{-6}	4	1.6×10^{-6}	4
Steam Generator Tube Rupture (SGTR)	1.2×10^{-6}	3	1.5×10^{-6}	4
General Transient and Loss of Main Feedwater (LMFW)	7.9×10^{-7}	2	6.8×10^{-7}	2
Total (Internal Events)[(a)]	**4.0×10^{-5}**	**100**	**3.8×10^{-5}**	**100**

[(a)] Column totals may be different due to round off.

As shown in these tables, internal event CDF is dominated by loss of SX, loss of component cooling water (CCW), and internal flooding for both units.

Exelon estimated the dose to the population within 50 mi (80 km) of the Byron site to be approximately 0.355 person-sievert (Sv) (35.5 person-rem) per year (Exelon 2013a) for internal events. The breakdown of the total population dose by containment release mode is summarized in Table 4–16. Containment overpressure accidents, interfacing-systems loss-of-coolant accident (ISLOCA), and steam generator tube rupture (SGTR) are the dominant contributors to population dose risk from internal events.

Table 4–16. Breakdown of Population Dose and Offsite Economic Cost by Containment Release Mode [(a)]

Containment Release Mode	Population Dose (person-rem [(b)] per year)	Percent Contribution	Offsite Economic Cost ($/yr)	Percent Contribution
Containment overpressure (late)	28.3	80	222,700	88
ISLOCA	4.42	12	11,800	5
Steam generator tube rupture	2.16	6	17,600	7
Containment isolation failure	0.34	<1	1,660	<1
Containment intact	0.13	<1	120	<1
Early containment failure	0.09	<1	580	<1
Basemat melt-through (late)	0.02	<1	40	<1
Total [(c)]	**35.5**	**100**	**255,000**	**100**

[(a)] Values in table derived from Table F.3-9 of the ER.
[(b)] 1 person-rem = 0.01 person-Sv.
[(c)] Column totals may be different due to round off.

The NRC staff has reviewed Exelon's data and evaluation methods and concludes that the quality of the risk analyses is adequate to support an assessment of the risk reduction potential for candidate SAMAs. Accordingly, the staff based its assessment of offsite risk on the CDFs and offsite doses reported by Exelon.

Potential Plant Improvements

Once the dominant contributors to plant risk were identified, Exelon searched for ways to reduce that risk. In identifying and evaluating potential SAMAs, Exelon considered insights from the plant-specific PRA and SAMA analyses performed for other operating plants that have submitted license renewal applications. This search included reviewing insights from the plant-specific risk studies, considering insights from the Byron PRA Group, and reviewing plant improvements considered in the IPE, IPEEE, and previous SAMA analyses. Exelon identified 30 potential risk-reducing improvements (SAMAs) to plant components, systems, procedures and training.

Exelon removed three of the SAMAs from further consideration because they are not applicable to Byron due to design differences, they have already been implemented at Byron or their intent is achieved by other means, or they have estimated implementation costs that would exceed the dollar value associated with completely eliminating all severe accident risk at Byron related to power generation operations. One additional candidate SAMA was further evaluated after accounting for analysis uncertainties. A detailed cost-benefit analysis was performed for each of the remaining 28 SAMAs.

The NRC staff concludes that Exelon used a systematic and comprehensive process for identifying potential plant improvements for Byron, and that the set of potential plant improvements identified by Exelon is reasonably comprehensive and, therefore, acceptable.

Cost-Benefit Comparison

The cost benefit analysis performed by Exelon was based primarily on NUREG/BR–0184 (NRC 1997) and was executed consistent with this guidance. NUREG/BR–0058 has recently been revised to reflect the agency's revised policy on discount rates. Revision 4 of NUREG/BR–0058 states that two sets of estimates should be developed—one at 3 percent and one at 7 percent (NRC 2004). Exelon provided both sets of estimates (Exelon 2013, 2014) and based its decisions on potentially cost-beneficial SAMAs on these values.

Exelon identified 10 potentially cost-beneficial SAMAs in the baseline analysis contained in its ER. The potentially cost-beneficial SAMAs are:

- SAMA 3 – Auto Start of Standby SX Pump;
- SAMA 5 – Modify the Startup Feedwater Pump to Start Using the AMSAC SG Low-Low-Low Level Signal to Mitigate AFW Failure;
- SAMA 9 – Install Flow Restrictors in Fire Protection Pipes;
- SAMA 10 – Alter Ductwork Between the Aux BLDG Room and the SX Pump Room;
- SAMA 13 – Alternate AFW Cooling with Seal Protection;
- SAMA 15 – Resolve Regulatory Issues and Complete Implementation of the Inter Unit AFW Cross-tie;
- SAMA 25 – Install a Filtered Containment Vent;
- SAMA 26 – DMS Using a Dedicated Generator, Self Cooled Charging Pump, and a Portable AFW Pump;
- SAMA 27 – Protect RHR,SI and CVCS Cubicle Cooling Fan Cables in Fire Zone 11.3-0; and
- SAMA 31 – Protect Cables for 2AF013A, B, and D in the AUX Building General Area, Elevation 426′.

Exelon performed additional analyses to evaluate the impact of parameter choices and uncertainties on the results of the SAMA assessment (Exelon 2013, 2014). If the benefits are increased by a factor of 2.53 to account for uncertainties, 10 additional SAMA candidates were determined to be potentially cost beneficial:

- SAMA 1 – Install Diesel Driven SX Pump in a New Dedicated Building;
- SAMA 2 – Replace the Positive Displacement Pump with a Self-Cooled, Auto Start Pump;
- SAMA 4 – Install "No Leak" Seals;
- SAMA 7 – Establish Flow to the RH HX on RH Pump Start;
- SAMA 8 – Install Kill Switches for the Fire Protection Pumps in the MCR;
- SAMA 11 – Implement DMS;
- SAMA 16 – Install High Flow Sensors on the Non-Essential Service Water System;
- SAMA 19 – Replace MOVs in the RHR Discharge Line with Valves that can Isolate an ISLOCA Event;

- SAMA 28 – Install Fire Barriers Around MCC 134X; and
- SAMA 30 – Protect AFW Cables in the AUX Building General Area, Elevation 383′.

Exelon stated in its ER that 18 of the SAMAs (SAMAs 2, 3, 5, 7, 8, 9, 10, 11, 13, 15, 16, 19, 25, 26, 27, 28, 30, and 31) determined to be cost beneficial in its ER baseline and uncertainty evaluations have been submitted to the Byron Plant Health Committee for further implementation consideration (Exelon 2013a). Exelon stated that installation of SAMA 4 at Byron is planned, that contract awards have already been made to install the new reactor coolant pump seals, and that engineering and analysis work necessary to install the new seals has already begun (Exelon 2014). Exelon also stated in its ER that SAMA 11 may be fully or partially implemented at Byron for other purposes, which, if fully implemented along with SAMA 15 (which is currently being implemented), would result in SAMA 1 no longer being cost beneficial. Since full implementation of SAMA 11 in conjunction with SAMA 15 would result in SAMA 1 not being cost beneficial, the NRC staff concludes that the applicant should consider SAMA 1 for further evaluation, depending on the degree of implementation of SAMA 11.

The NRC staff concludes that, with the exception of the potentially cost-beneficial SAMAs discussed above, the costs of the SAMAs evaluated would be higher than the associated benefits when they are considered independently.

Conclusions

The NRC staff reviewed Exelon's analysis and concludes that the methods used and the implementation of those methods were sound. The treatment of SAMA benefits and costs support the general conclusion that the SAMA evaluations performed by Exelon are reasonable and sufficient for the license renewal submittal.

Based on its review of the SAMA analysis, the NRC staff finds Exelon's identification of areas in which risk can be further reduced in a cost-beneficial manner through the implementation of all or a subset of potentially cost-beneficial SAMAs to be acceptable. Given the potential for cost-beneficial risk reduction, the staff considers that further evaluation of these SAMAs by Exelon is warranted. Additionally, the NRC staff evaluated the identified potentially cost-beneficial SAMAs to determine if they are in the scope of license renewal, (i.e., they are subject to aging management). This evaluation considers whether the SSCs associated with these SAMAs: (1) perform their intended function without moving parts or without a change in configuration or properties and (2) are not subject to replacement based on qualified life or specified time period. The NRC staff determined that these SAMAs do not relate to adequately managing the effects of aging during the period of extended operation. Therefore, they need not be implemented as part of the license renewal pursuant to 10 CFR Part 54.

4.11.2 No-Action Alternative

Human health risks would be smaller following plant shutdown. The two reactor units, which are currently operating within regulatory limits, would emit less radioactive gaseous, liquid, and solid material to the environment. In addition, following shutdown, the variety of potential accidents at the plant (radiological or industrial) would be reduced to a limited set associated with shutdown events and fuel handling and storage. In Section 4.11.1, the NRC staff concluded that the impacts of continued plant operation on human health would be SMALL, except for "Chronic effects of electromagnetic fields (EMFs)," for which the impacts are UNCERTAIN. In Section 4.11.1.2, the NRC staff concluded that the impacts of accidents during operation are SMALL. Therefore, as radioactive emissions to the environment decrease, and as the likelihood and types of accidents decrease following shutdown, the NRC staff concludes that the risk to human health following plant shutdown would be SMALL.

4.11.3 New Nuclear Alternative

Impacts on human health from construction of two new nuclear units would be similar to impacts associated with the construction of any major industrial facility. Compliance with worker protection rules would control those impacts on workers at acceptable levels. Impacts from construction on the general public would be minimal since limiting active construction area access to authorized individuals is expected. Impacts on human health from the construction of two new nuclear units would be SMALL.

The human health effects from the operation of two new nuclear power plants would be similar to those of the existing Byron. As presented in Section 4.11.1.1, impacts on human health from the operation of Byron would be SMALL, except for “Chronic effects of electromagnetic fields (EMFs),” for which the impacts are UNCERTAIN. Therefore, the impacts on human health from the operation of two new nuclear plants would be SMALL.

4.11.4 IGCC Alternative

Impacts on workers are expected to be similar to those experienced during construction of any major industrial facility. Impacts from construction of combustion-based renewable energy facilities are expected to be the same as those for construction of fossil fuel facilities. Construction would increase traffic on local roads, which could affect the health of the general public. Human health impacts would be the same for all facilities whether located on greenfield sites or at an existing nuclear plant. Personal protective equipment, training, and engineered barriers would protect the workforce (NRC 2013a). Therefore, the impacts on human health from the construction of an IGCC facility would be SMALL.

The IGCC alternative introduces worker risks from coal and limestone mining, worker and public risk from coal and lime/limestone transportation, worker and public risk from disposal of coal-combustion waste, and public risk from inhalation of stack emissions. In addition, human health risks are associated with the management and disposal of coal combustion waste. Coal combustion generates waste in the form of ash, and equipment for controlling air pollution generates additional ash and scrubber sludge. Human health risks may extend beyond the facility workforce to the public depending on their proximity to the coal combustion waste disposal facility. The character and the constituents of coal combustion waste depend on both the chemical composition of the source coal and the technology used to combust it. Generally, the primary sources of adverse consequences from coal combustion waste are from exposure to sulfur oxide and nitrogen oxide in air emissions and radioactive elements such as uranium and thorium as well as the heavy metals and hydrocarbon compounds contained in fly ash and bottom ash, and scrubber sludge (NRC 2013a).

Regulatory agencies, including EPA and state agencies, base air emission standards and requirements on human health impacts. These agencies also impose site-specific emission limits as needed to protect human health. Given the regulatory oversight exercised by EPA and state agencies, the NRC staff concludes that the human health impacts from radiological doses and inhaled toxins and particulates generated from the IGCC alternative would be SMALL (NRC 2013a).

4.11.5 NGCC Alternative

Impacts on human health from construction of the NGCC alternative would be similar to effects associated with the construction of any major industrial facility. Compliance with worker protection rules would control those impacts on workers at acceptable levels. Impacts from construction on the general public would be minimal since crews would limit active construction area access to authorized individuals. Based on the above, the NRC staff concludes that the impacts on human health from the construction of the NGCC alternative would be SMALL.

Impacts from the operation of an NGCC facility introduces public risk from inhalation of gaseous emissions. The risk may be attributable to nitrogen oxide emissions that contribute to ozone formation, which in turn contribute to health risk. Regulatory agencies, including EPA and state agencies, base air emission standards and requirements on human health impacts. These agencies also impose site-specific emission limits as needed to protect human health. Given the regulatory oversight exercised by EPA and state agencies, the NRC staff concludes that the human health impacts from the NGCC alternative would be SMALL.

4.11.6 Combination Alternative (NGCC, Wind, Solar)

Impacts on human health from construction of a combination of NGCC, wind, and solar PV alternatives would be similar to those associated with the construction of any major industrial facility. Compliance with worker protection rules would control those impacts on workers at acceptable levels. Impacts from construction on the general public would be minimal since crews would limit active construction area access to authorized individuals. Based on the above, the NRC staff concludes that the impacts on human health from the construction of the NGCC, wind, and solar alternative would be SMALL.

Operational hazards at an NGCC facility are similar to those at an IGCC facility and are discussed in Section 4.11.4.

Operational hazards at a wind facility for the workforce include working at heights, near rotating mechanical or electrically energized equipment, and working in extreme weather. Potential impacts to workers and the public include ice thrown from rotor blades and broken blades thrown due to mechanical failure. Potential impacts also include EMF exposure, aviation safety hazard, and exposure to noise and vibration from the rotating blades.

Operational hazards at a solar PV facility may involve exposure to airborne toxic metals (e.g., cadmium) and silicon if the PV cell loses its integrity from a fire. Workers could also inhale silicon dust if the PV cell was smashed by an object or from a fall to the ground.

However, given the expected compliance with worker protection rules and remediation efforts to contain the toxic material, the potential impacts to workers at the facility and offsite exposure to the public, the impacts would be SMALL.

4.11.7 Purchased Power

Purchased power is expected to come from the types of electricity generation available within the ROI: coal, natural gas, nuclear, and wind. The human health impacts from the operation of these types of power plants are discussed in Sections 4.11.3, 4.11.4, 4.11.5, and 4.11.6. Based on the information in those sections, the NRC staff concludes that the human health impacts of the purchased power alternative using coal, natural gas, nuclear, and wind would be SMALL.

4.12 Environmental Justice

This section describes the potential human health and environmental effects of the proposed action (license renewal) and alternatives to the proposed action on minority and low-income populations and special pathway receptors.

4.12.1 Proposed Action

The environmental justice issue applicable to Byron during the license renewal term is listed in Table 4–17. Section 3.12 of this SEIS describes the environmental justice matters with respect to Byron.

Table 4–17. Environmental Justice

Issue	GEIS Section	Category
Minority and low-income populations	4.10.1	2

Source: Table B–1 in Appendix B, Subpart A, to 10 CFR Part 51

The NRC addresses environmental justice matters for license renewal by (1) identifying the location of minority and low-income populations that may be affected by the continued operation of the nuclear power plant during the license renewal term, (2) determining whether there would be any potential human health or environmental effects to these populations and special pathway receptors, and (3) determining if any of the effects may be disproportionately high and adverse. Adverse health effects are measured in terms of the risk and rate of fatal or nonfatal adverse impacts on human health. Disproportionately high and adverse human health effects occur when the risk or rate of exposure to an environmental hazard for a minority or low-income population is significant and exceeds the risk or exposure rate for the general population or for another appropriate comparison group. Disproportionately high environmental effects refer to impacts or risks of impacts on the natural or physical environment in a minority or low-income community that are significant and appreciably exceed the environmental impact on the larger community. Such effects may include biological, cultural, economic, or social impacts.

As discussed above, the environmental justice impact analysis evaluates the potential for disproportionately high and adverse human health and environmental effects on minority and low-income populations. Some of these potential effects have been identified in resource areas discussed in this SEIS. For example, increased demand for rental housing during replacement power plant construction could disproportionately affect low-income populations. Minority and low-income populations are subsets of the general public residing in the vicinity of all the alternatives listed below, and all are exposed to the same hazards generated by each alternative.

Figures 3–15 and 3–16 show the location of predominantly minority and low-income population block groups residing within a 50-mi (80-km) radius of Byron. This area of impact is consistent with the impact analysis for public and occupational health and safety, which also focuses on populations within a 50-mi (80-km) radius of the plant. Chapter 4 presents the assessment of environmental and human health impacts for each resource area. The analyses of impacts for all environmental resource areas indicated that the impact from license renewal would be SMALL.

Potential impacts on minority and low-income populations (including migrant workers or Native Americans) would mostly consist of socioeconomic and radiological effects; however, radiation doses from continued operations during the license renewal term are expected to continue at current levels, and they would remain within regulatory limits. Section 4.11.1.2 of this SEIS discusses the environmental impacts from postulated accidents that might occur during the license renewal term, which include both design-basis and severe accidents. In both cases, the Commission has generically determined that impacts associated with DBAs are small because nuclear plants are designed and operated to successfully withstand such accidents, and the probability weighted consequences of severe accidents are small.

Therefore, based on this information and the analysis of human health and environmental impacts presented in Chapter 4 of this SEIS, there would be no disproportionately high and adverse human health and environmental effects on minority and low-income populations from the continued operation of Byron during the license renewal term.

As part of addressing environmental justice concerns associated with license renewal, the NRC staff also assessed the potential radiological risk to special population groups (such as migrant workers or Native Americans) from exposure to radioactive material received through their unique consumption practices and interaction with the environment, including subsistence consumption of fish, native vegetation, surface waters, sediments, and local produce; absorption of contaminants in sediments through the skin; and inhalation of airborne radioactive material released from the plant during routine operation. This analysis is presented below.

Subsistence Consumption of Fish and Wildlife

The special pathway receptors analysis is an important part of the environmental justice analysis because consumption patterns may reflect the traditional or cultural practices of minority and low-income populations in the area, such as migrant workers or Native Americans.

Section 4-4 of Executive Order (EO) 12898 (1994) (59 FR 7629) directs Federal agencies, whenever practical and appropriate, to collect and analyze information about the consumption patterns of populations that rely principally on fish or wildlife for subsistence and to communicate the risks of these consumption patterns to the public. In this SEIS, the NRC staff considered whether there were any means for minority or low-income populations to be disproportionately affected by examining impacts on American Indian, Hispanics, migrant workers, and other traditional lifestyle special pathway receptors. The assessment of special pathways considered the levels of radiological and nonradiological contaminants in native vegetation, crops, soils and sediments, groundwater, surface water, fish, and game animals on or near Byron.

The following is a summary discussion of Exelon's radiological environmental monitoring programs (REMPs) that assess the potential impacts from the subsistence consumption of fish and wildlife near the Byron site.

Exelon has an ongoing comprehensive REMP to assess the impact of Byron operations on the environment. To assess the impact of nuclear power plant operations, samples are collected annually from the environment and analyzed for radioactivity. A plant effect would be indicated if the radioactive material detected in a sample were significantly larger than background levels. Two types of samples are collected. The first type, a control sample, is collected from areas that are beyond the measurable influence of the nuclear power plant or any other nuclear facility. These samples are used as reference data to determine normal background levels of radiation in the environment. These samples are then compared with the second type of samples, indicator samples, collected near the nuclear power plant. Indicator samples are collected from areas where any contribution from the nuclear power plant will be at its highest concentration. These samples are then used to evaluate the contribution of nuclear power plant operations to radiation or radioactivity levels in the environment. An effect would be indicated if the radioactivity levels detected in an indicator sample were significantly larger than the control sample or background levels.

Samples of environmental media are collected from the aquatic and terrestrial pathways in the vicinity of Byron. The aquatic pathways include groundwater, surface water, fish, and shoreline sediment. The terrestrial pathways include airborne particulates, milk, and food products (i.e., cabbage, beets and beet greens, kohlrabi, potatoes, rhubarb leaves, onions, and turnips). During 2012, 1,480 analyses performed on 913 samples of environmental media at Byron showed no significant or measurable radiological impact above background levels from site operations (Teledyne 2013).

Conclusion

Based on the radiological environmental monitoring data from Byron, the NRC staff finds that no disproportionately high and adverse human health impacts would be expected in special pathway receptor populations in the region as a result of subsistence consumption of water, local food, fish, and wildlife. Continued operation of Byron would not have disproportionately high and adverse human health and environmental effects on these populations.

4.12.2 No-Action Alternative

Impacts on minority and low-income populations would depend on the number of jobs and the amount of tax revenues lost by communities in the immediate vicinity of the power plant after Byron ceases operations. Not renewing the operating licenses and terminating reactor operations would have a noticeable impact on socioeconomic conditions in the communities located near Byron. The loss of jobs and income would have an immediate socioeconomic impact. Some, but not all, of the approximately 890 employees would begin to leave after reactor operations are terminated; and overall tax revenue generated by plant operations would be reduced. The reduction in tax revenue would decrease the availability of public services in Ogle County. This could disproportionately affect minority and low-income populations that may have become dependent on these services. Effects could be high or adverse depending on the needs of the individual impacted. See also Appendix J of NUREG–0586, Supplement 1 (NRC 2002), for additional discussion of these impacts.

4.12.3 New Nuclear Alternative

Potential impacts to minority and low-income populations from the construction and operation of a new nuclear power plant would mostly consist of environmental and socioeconomic effects (e.g., noise, dust, traffic, employment, and housing impacts). Noise and dust impacts from construction would be short-term and primarily limited to onsite activities. Minority and low-income populations residing along site access roads would be affected by increased commuter vehicle traffic during shift changes and truck traffic. However, these effects would be temporary during certain hours of the day and would not likely be high and adverse. Increased demand for rental housing during construction could affect low-income populations. However, given the proximity of some existing nuclear power plant sites to metropolitan areas, many construction workers could commute to the site, thereby reducing the potential demand for rental housing.

Potential impacts to minority and low-income populations from new nuclear power plant operations would mostly consist of radiological effects; however, radiation doses are expected to be well below regulatory limits. All people living near the nuclear power plant would be exposed to the same potential effects from power plant operations, and any impacts would depend on the magnitude of the change in ambient air quality conditions. Permitted air emissions are expected to remain within regulatory standards.

Based on this information and the analysis of human health and environmental impacts presented in this SEIS, the construction and operation of a new nuclear power plant would not have disproportionately high and adverse human health and environmental effects on minority and low-income populations.

4.12.4 IGCC Alternative

Potential impacts to minority and low-income populations from the construction and operation of a new IGCC plant at the Byron site or an existing power plant site would consist of environmental and socioeconomic effects (e.g., noise, dust, traffic, employment, and housing impacts). Noise and dust impacts from construction would be short-term and primarily limited to onsite activities. Minority and low-income populations residing along site access roads would be affected by increased commuter vehicle traffic during shift changes and truck traffic. However, these effects would be temporary during certain hours of the day and would not likely be high and adverse. Increased demand for rental housing during construction could affect low-income populations. However, given the proximity of some existing power plant sites and the Byron site to metropolitan areas, many construction workers could commute to the site, thereby reducing the potential demand for rental housing.

Emissions from the operation of an IGCC plant could affect minority and low-income populations as well as the general population living in the vicinity of the new power plant. However, all would be exposed to the same potential effects from IGCC power plant operations and any impacts would depend on the magnitude of the change in ambient air quality conditions. Permitted air emissions are expected to remain within regulatory standards.

Based on this information and the analysis of human health and environmental impacts presented in this SEIS, the construction and operation of a new IGCC plant would not have disproportionately high and adverse human health and environmental effects on minority and low-income populations.

4.12.5 NGCC Alternative

Potential impacts to minority and low-income populations from the construction and operation of a new NGCC plant at the Byron site or an existing power plant site would mostly consist of environmental and socioeconomic effects (e.g., noise, dust, traffic, employment, and housing impacts). Noise and dust impacts from construction would be short-term and primarily limited to onsite activities. Minority and low-income populations residing along site access roads would be affected by increased commuter vehicle traffic during shift changes and truck traffic. However, these impacts would only be during certain hours of the day and would not likely be high and adverse. Increased demand for rental housing during construction could affect low-income populations. However, given the proximity of some existing power plant sites and the Byron site to metropolitan areas, many construction workers could commute to the site, thereby reducing the potential demand for rental housing.

Emissions from the operation of an NGCC plant could affect minority and low-income populations as well as the general population living in the vicinity of the new power plant. However, all would be exposed to the same potential effects from NGCC power plant operations, and any impacts would depend on the magnitude of the change in ambient air quality conditions. Permitted air emissions are expected to remain within regulatory standards.

Based on this information and the analysis of human health and environmental impacts presented in this SEIS, the construction and operation of a new NGCC plant would not have disproportionately high and adverse human health and environmental effects on minority and low-income populations.

4.12.6 Combination Alternative (NGCC, Wind, Solar)

Potential impacts to minority and low-income populations from the construction and operation of a new NGCC plant, wind turbines, and solar PV installations would mostly consist of environmental and socioeconomic effects (e.g., noise, dust, traffic, employment, and housing impacts). Noise and dust impacts from construction would be short-term and primarily limited to onsite activities. Minority and low-income populations residing along site access roads would be affected by increased commuter vehicle traffic during shift changes and truck traffic. However, these impacts would only be during certain hours of the day and would not likely be high and adverse. Increased demand for rental housing during construction could affect low-income populations. However, given the small number of construction workers and the possibility that many workers could commute to these construction sites, the potential need for rental housing would not be significant.

Minority and low-income populations living in close proximity to wind farm and solar PV power generating installations could be disproportionately affected by maintenance and operations activities. However, everyone would be exposed to the same operational impacts, and any impact would depend on the magnitude of change from current conditions. Operational impacts from the wind turbines and solar PV installations would mostly be limited to noise and aesthetic effects. The general public living near the wind farms and solar PV installations would also be exposed to the same effects.

Based on this information and the analysis of human health and environmental impacts presented in this SEIS, the construction and operation of a new NGCC plant, wind farms, and solar PV installations would not have disproportionately high and adverse human health and environmental effects on minority and low-income populations.

4.12.7 Purchased Power

Low-income populations could be disproportionately affected by increased utility bills because of the cost of purchased power. However, programs, such as the low income home energy assistance program in Illinois, are available to assist low-income families in paying for increased electrical costs.

4.13 Waste Management and Pollution Prevention

This section describes the potential impacts of the proposed action (license renewal) and alternatives to the proposed action on waste management and pollution prevention.

4.13.1 Proposed Action

The waste management issues applicable to Byron are discussed below and listed in Table 4–18. Table B-1 of Appendix B to Subpart A of 10 CFR Part 51 contains more information on these issues.

Table 4–18. Waste Management Issues

Issue	GEIS Section	Category
Low-level waste storage and disposal	4.11.1.1	1
Onsite storage of spent nuclear fuel	4.11.1.2[(a)]	1
Offsite radiological impacts of spent nuclear fuel and high-level waste disposal	4.11.1.3[(b)]	1
Mixed-waste storage and disposal	4.11.1.4	1
Nonradioactive waste storage	4.11.1.4	1

[(a)] The environmental impact of this issue for the timeframe beyond the licensed life for reactor operations is contained in NUREG-2157 (NRC 2014a).

[(b)] The environmental impact of this issue is contained in NUREG-2157 (NRC 2014a).

Source: Table B-1 in Appendix B, Subpart A, to 10 CFR Part 51

The NRC staff's evaluation of the environmental impacts associated with spent nuclear fuel is addressed in two issues in Table 4–18, "Onsite storage of spent nuclear fuel" and "Offsite radiological impacts of spent nuclear fuel and high-level waste disposal." However, as explained later in this section, these two issues now incorporate the generic environmental impact determinations codified in the revised 10 CFR 51.23 pursuant to the Continued Storage Rule (79 FR 56238)[9].

The NRC staff did not identify any new and significant information related to waste management issues listed in Table 4–18 during its review of the applicant's ER (Exelon 2013a), the site visit, or the scoping process. Therefore, there are no impacts related to these issues beyond those discussed in the GEIS (NRC 2013a) and the "Generic Environmental Impact Statement for Continued Storage of Spent Nuclear Fuel, Volumes 1 and 2" (NUREG-2157) (NRC 2014a). During the license renewal term, for these Category 1 issues discussed in the GEIS, the NRC staff concludes that the impacts are SMALL.

4.13.1.1 10 CFR 51.23 (Continued Storage Rule) and 10 CFR 51, Subpart A, Table B-1 (License Renewal)

The NRC's findings regarding the environmental impacts associated with the renewal of a power reactor operating license are contained in Table B-1, "Summary of Findings on NEPA Issues for License Renewal of Nuclear Power Plants." The table is located in Appendix B to Subpart A of 10 CFR Part 51, "Environmental Effect of Renewing the Operating License of a Nuclear Power Plant"[10] (Table B-1). In 1996, as part of the 10 CFR Part 51 license renewal rulemaking, the NRC determined that offsite radiological impacts of spent nuclear fuel and high-level waste disposal would be a Category 1 (generic) issue with no impact level assigned (61 FR 28467, 28495; June 5, 1996). The NRC analyzed the EPA generic repository standards and dose limits in existence at the time and concluded that offsite radiological impacts warranted a Category 1 determination (61 FR 28467, 28478; June 5, 1996). In its 2009

[9] 79 FR 56238. U.S. Nuclear Regulatory Commission. "Continued Storage of Spent Nuclear Fuel." Federal Register 79 (182):56238–56263. September 19, 2014.

[10] The Commission issued Table B-1 in June 1996 (61 FR 28467; June 5, 1996). The Commission issued an additional rule in December 1996 that made minor clarifying changes to, and added language inadvertently omitted from, Table B-1 (61 FR 66537; December 18, 1996). The NRC revised Table B-1 and other regulations in 10 CFR Part 51, relating to the NRC's environmental review of a nuclear power plant's license renewal application in a 2013 rulemaking (78 FR 37282; June 20, 2013).

proposed rule, the NRC stated its intention to reaffirm that determination (74 FR 38117, 38127; July 31, 2009).

For the offsite radiological impacts resulting from spent fuel and high-level waste disposal and the onsite storage of spent fuel, which will occur after the reactors have been permanently shutdown, the NRC's Waste Confidence Decision and Temporary Storage Rule (WCD and rule) (10 CFR 51.23) historically represented the Commission's generic determination that spent fuel can continue to be stored safely and without significant environmental impacts for a period of time after the end of the licensed life for operation. This generic determination meant that the NRC did not need to consider the storage of spent fuel after the end of a reactor's licensed life for operation in NEPA documents that support its reactor and spent fuel storage application reviews.

The NRC first adopted the Waste Confidence Decision and Rule in 1984. The NRC amended the decision and rule in 1990, reviewed them in 1999, and amended them again in 2010, as published in the *Federal Register* (FR) (49 FR 34685, 34694; 55 FR 38472, 38474; 64 FR 68005; and 75 FR 81032 and 81037). The Waste Confidence Decision and Rule are codified in 10 CFR 51.23.

On December 23, 2010, the Commission published in the FR a revision of the Waste Confidence Decision and Rule to reflect information gained from experience in the storage of spent fuel and the increased uncertainty in the siting and construction of a permanent geologic repository for the disposal of spent fuel and high-level waste (75 FR 81032 and 81037). In response to the 2010 Waste Confidence Decision and Rule, the States of New York, New Jersey, Connecticut, and Vermont—along with several other parties—challenged the Commission's NEPA analysis in the decision, which provided the regulatory basis for the rule. On June 8, 2012, the United States Court of Appeals, District of Columbia Circuit in *New York* v. *NRC*, 681 F.3d 471 (D.C. Cir. 2012), vacated the NRC's Waste Confidence Decision and Rule after finding that it did not comply with NEPA.

In response to the court's ruling, the Commission, in CLI-12-16 (NRC 2012a), determined that it would not issue licenses that rely upon the Waste Confidence Decision and Rule until the issues identified in the court's decision are appropriately addressed by the Commission. In CLI-12-16, the Commission also noted that the decision not to issue licenses only applied to final license issuance; all licensing reviews and proceedings should continue to move forward.

In addition, the Commission directed in SRM-COMSECY-12-0016 (NRC 2012b) that the NRC staff proceed with a rulemaking that includes the development of a generic EIS to support a revised Waste Confidence Decision and Rule and to publish both the EIS and the revised decision and rule in the FR within 24 months (by September 2014). The Commission indicated that both the EIS and the revised Waste Confidence Decision and Rule should build on the information already documented in various NRC studies and reports, including existing EAs that the NRC developed as part of the 2010 Waste Confidence Decision and Rule. The Commission directed that any additional analyses should focus on the issues identified in the court's decision. The Commission also directed that the NRC staff provide ample opportunity for public comment on both the draft EIS and the proposed Waste Confidence Decision and Rule.

As discussed above, in *New York v. NRC*, 681 F.3d 471 (D.C. Cir. 2012), the court vacated the Commission's Waste Confidence Decision and Rule (10 CFR 51.23). In response to the court's *vacatur*, the Commission developed a revised rule and associated *Generic Environmental Impact Statement for Continued Storage of Spent-Nuclear Fuel* (NUREG-2157). Before the issuance of the revised 10 CFR 51.23 and NUREG-2157, the NRC issued the 2013 final license renewal rule, which amended Table B-1—along with other 10 CFR Part 51 regulations—and stated that upon finalization of the revised Waste Confidence rule and accompanying technical analyses,[11] the NRC would make any necessary conforming amendments to Table B-1 (78 FR 37282, 37293; June 20, 2013).

On August 26, 2014, the Commission approved the Continued Storage Rule and associated *Generic Environmental Impact Statement for Continued Storage of Spent Nuclear Fuel* (NUREG-2157, NRC 2014a). Subsequently, on September 19, 2014, the NRC published the final rule (79 FR 56238) in the *Federal Register,* along with NUREG-2157 (79 FR 53238, 56263). The Continued Storage Rule adopts the generic impact determinations made in NUREG-2157 and codifies the NRC's generic determinations regarding the environmental impacts of continued storage of spent nuclear fuel beyond a reactor's operating license (i.e., those impacts that could occur as a result of the storage of spent nuclear fuel at at-reactor or away-from-reactor sites after a reactor's licensed life for operation and until a permanent repository becomes available). As directed by 10 CFR 51.23(b), the impacts assessed in NUREG-2157 regarding continued storage are deemed incorporated by rule into this license renewal SEIS.

In the Continued Storage Rule, the NRC made conforming changes to the two environmental issues in Table B-1 that were impacted by the vacated Waste Confidence rule: "Onsite spent fuel" and "Offsite radiological impacts (spent fuel and high-level waste disposal)."[12] Although NUREG-2157 (the technical basis for the Continued Storage Rule) does not include high-level waste disposal in the analysis of impacts, it does address the technical feasibility of a repository in Appendix B of NUREG-2157 and concludes that a geologic repository for spent fuel is technically feasible and the same analysis applies to the feasibility of geologic disposal for high-level waste.

The Commission revised the Table B-1 finding for "Onsite storage of spent nuclear fuel" to add the phrase "during the license renewal term" to make clear that the SMALL impact is for the license renewal term only. Some minor clarifying changes were also made to the paragraph. The first paragraph of the column entry now reads, "During the license renewal term, SMALL. The expected increase in the volume of spent nuclear fuel from an additional 20 years of operation can be safely accommodated onsite during the license renewal term with small environmental impacts through dry or pool storage at all plants."

In addition, a new paragraph is added to address the impacts of onsite storage of spent fuel during the continued storage period. The second paragraph of the column entry reads, "For the period after the licensed life for reactor operations, the impacts of onsite storage of spent nuclear fuel during the continued storage period are discussed in NUREG-2157 and as stated in § 51.23(b), shall be deemed incorporated into this issue." The changes reflect that this issue covers the environmental impacts associated with the storage of spent nuclear fuel during the license renewal term as well as the period after the licensed life for reactor operations.

The Table B-1 entry for "Offsite radiological impacts of spent nuclear fuel and high-level waste disposal" also was revised to reclassify the impact determination as a Category 1 issue with no impact level assigned. The finding column entry for this issue includes reference to EPA's radiation protection standards for the high-level waste and spent nuclear fuel disposal component of the fuel cycle. Although the status of a repository, including a repository at Yucca Mountain, is uncertain and outside the scope of the generic environmental analysis conducted

[11]At the time of the 2013 final license renewal rule, the Continued Storage Rule was referred to by its long-standing historical moniker, Waste Confidence.

[12]These two issues were renamed, ''Onsite storage of spent nuclear fuel' and ''Offsite radiological impacts of spent nuclear fuel and high-level waste disposal,'' respectively, by the 2013 license renewal rule. See "Revisions to Environmental Review for Renewal of Nuclear Power Plant Operating Licenses," 78 FR 37282–37324 (June 20, 2013).

to support the Continued Storage Rule, the NRC believes that the current radiation standards for Yucca Mountain are protective of public health and safety and the environment.

The changes to these two issues finalize the Table B-1 entries that the NRC had intended to issue in its 2013 license renewal rulemaking, but was unable to because the 2010 Waste Confidence rule had been vacated.

NUREG-2157 concludes that deep geologic disposal remains technically feasible, while the bases for the specific conclusions in Table B-1 are found elsewhere (e.g., the 1996 rule that issued Table B-1 and the 1996 license renewal GEIS, which provided the technical basis for that rulemaking, as reaffirmed by the 2013 rulemaking and final license renewal GEIS). Based on the Continued Storage Rule, these two issues were revised accordingly in Table B-1.

4.13.1.2 CLI-14-08: Holding that Revised 10 CFR 51.23 and NUREG-2157 Satisfy NRC's NEPA Obligations for Continued Storage and Directing Staff to Account for Environmental Impacts In NUREG-2157

In CLI-14-08 (NRC 2014b), the Commission held that the revised 10 CFR 51.23 and associated NUREG-2157 cure the deficiencies identified by the court in *New York* and stated that the rule satisfies the NRC's NEPA obligations with respect to continued storage for initial, renewed, and amended licenses for reactors.

As the Commission noted in CLI-14-08, the NRC staff must account for these environmental impacts before finalizing its licensing decision in this proceeding. To account for these impact determinations, the generic environmental impact determinations made pursuant to the Continued Storage Rule and the associated NUREG-2157 are deemed incorporated into this SEIS.

The NRC staff relies on the Continued Storage Rule and its supporting generic environmental impact statement (i.e., NUREG-2157) to provide the NEPA analyses of the environmental impacts of spent fuel storage at the reactor site or at an away-from-reactor storage facility beyond the licensed life for reactor operations. By virtue of the revised 10 CFR 51.23, the impact determinations in NUREG-2157 regarding continued storage complete the analysis of the environmental impacts associated with spent fuel storage beyond the licensed life for reactor operations and are deemed incorporated into this SEIS, as further described below.

4.13.1.3 At-Reactor Storage

The analysis in NUREG-2157 concludes that the potential impacts of at-reactor storage during the short-term timeframe (the first 60 years after the end of licensed life for operations of the reactor) would be SMALL (see Section 4.20 of NUREG-2157). Furthermore, the analysis in NUREG-2157 states that disposal of the spent fuel by the end of the short-term timeframe is the most likely outcome (see Section 1.2 of NUREG-2157).

However, the analysis in NUREG-2157 also evaluated the potential impacts of continued storage if the fuel is not disposed of by the end of the short-term timeframe. The analysis in NUREG-2157 determined that the impacts to historic and cultural resources from at-reactor storage during the long-term timeframe (the 100-year period after the short-term timeframe) and the indefinite timeframe (the period after the long-term timeframe) are dependent on factors that are unpredictable this far in advance and therefore concluded those impacts would be SMALL to LARGE (see Section 4.12 of NUREG-2157). Among other things, as discussed in NUREG-2157, the NRC cannot accurately determine at this time what resources may be present or discovered at a continued storage site a century or more in the future and whether those resources will be historically or culturally significant to future generations. Additionally, impacts greater than SMALL could occur if the activities to replace an independent spent fuel storage installation (ISFSI) and the dry transfer system (DTS) adversely affect cultural or historic resources and the effects cannot be mitigated. As discussed in NUREG-2157, given the minimal size of an ISFSI and DTS, and the large land areas at nuclear power plant sites, licensees should be able to locate these facilities away from historic and cultural resources. Potential adverse effects on historic properties or impacts on historic and cultural resources could also be minimized through development of agreements, license conditions, and implementation of the licensee's historic and cultural resource management plans and procedures to protect known historic and cultural resources and address inadvertent discoveries during construction and replacement of these facilities. However, it may not be possible to avoid adverse effects on historic properties under the National Historic Preservation Act of 1966 (NHPA), as amended, or impacts on historic and cultural resources under NEPA and, therefore, the analysis in NUREG-2157 concluded that impacts would be SMALL to LARGE (see Section 4.12.2 of NUREG-2157).

The analysis in NUREG-2157 also concludes that the impacts of nonradioactive waste in the indefinite timeframe would be SMALL to MODERATE, with the higher impacts potentially occurring if the waste from repeated replacement of the ISFSI and DTS exceeds local landfill capacity (see Section 4.15 of NUREG-2157). Although the NRC concluded that nonradioactive waste disposal would not be destabilizing (or LARGE), the range reflects uncertainty regarding whether the volume of nonradioactive waste from continued storage would contribute to noticeable waste management impacts over the indefinite timeframe when considered in the context of the overall local volume of nonradioactive waste.

As previously discussed, the NRC found in NUREG-2157 that disposal of the spent fuel is most likely to occur by the end of the short-term timeframe. Therefore, disposal during the long-term timeframe is less likely, and the scenario depicted in the indefinite timeframe—continuing to store spent nuclear fuel indefinitely—is unlikely. As a result, the most likely impacts of the continued storage of spent fuel are those considered in the short-term timeframe. In the unlikely event that fuel remains on site into the long-term and indefinite timeframes, the associated impact ranges in NUREG-2157 reflect the accordingly greater uncertainties regarding the potential impacts over these very long periods of time. Taking into account the impacts that the NRC considers most likely, which are SMALL; the greater uncertainty reflected in the ranges in the long-term and indefinite timeframes compared to the greater certainty in the SMALL findings; and the relative likelihood of the timeframes, the impact determinations for at-reactor storage presented in NUREG-2157 are deemed incorporated into this SEIS pursuant to 10 CFR 51.23.

4.13.1.4 Away-From-Reactor Storage

In NUREG-2157, the NRC concluded that a range of potential impacts could occur for some resource areas if the spent fuel from multiple reactors is shipped to a large (roughly 40,000 metric tons Uranium) away-from-reactor ISFSI (see Section 5.20 of NUREG-2157). The ranges for some resources are driven by the uncertainty regarding the location of such a facility and the local resources that would be affected.

For away-from-reactor storage, the unavoidable adverse environmental impacts for most resource areas is SMALL across all timeframes, except for air quality, terrestrial resources, aesthetics, waste management, and transportation where the impacts are SMALL to MODERATE. Socioeconomic impacts range from SMALL (adverse) to LARGE (beneficial) and historic and cultural resource impacts could be SMALL to LARGE across all timeframes. The potential MODERATE impacts on air quality, terrestrial wildlife, and transportation are based on potential construction-related fugitive dust emissions, terrestrial wildlife direct and indirect mortalities, terrestrial habitat loss, and temporary construction traffic impacts. The potential

MODERATE impacts on aesthetics and waste management are based on noticeable changes to the viewshed from constructing a new away-from-reactor ISFSI, and the volume of nonhazardous solid waste generated by assumed facility ISFSI and DTS replacement activities for the indefinite timeframe, respectively. The potential LARGE beneficial impacts on socioeconomics are due to local economic tax revenue increases from an away-from-reactor ISFSI.

The potential impacts to historic and cultural resources during the short-term storage timeframe would range from SMALL to LARGE. The magnitude of adverse effects on historic properties and impacts on historic and cultural resources largely depends on where facilities are sited, what resources are present, the extent of proposed land disturbance, whether the area has been previously surveyed to identify historic and cultural resources, and if the licensee has management plans and procedures that are protective of historic and cultural resources. Even a small amount of ground disturbance (e.g., clearing and grading) could affect a small but significant resource. In most instances, placement of storage facilities on the site can be adjusted to minimize or avoid impacts on any historic and cultural resources in the area. However, the NRC recognizes that this may not always be possible. The NRC's site-specific environmental review and compliance with the NHPA process could identify historic properties, identify adverse effects, and potentially resolve adverse effects on historic properties and impacts on other historic and cultural resources. Under the NHPA, mitigation does not eliminate a finding of adverse effect on historic properties. The potential impacts to historic and cultural resources during the long-term and indefinite storage timeframes would also range from SMALL to LARGE. This range takes into consideration routine maintenance and monitoring (i.e., no ground-disturbing activities), the absence or avoidance of historic and cultural resources, and potential ground-disturbing activities that could affect historic and cultural resources. The analysis also considers uncertainties inherent in analyzing this resource area over long timeframes. These uncertainties include any future discovery of previously unknown historic and cultural resources; resources that gain significance within the vicinity and the viewshed (e.g., nomination of a historic district) due to improvements in knowledge, technology, and excavation techniques and changes associated with predicting resources that future generations will consider significant. If construction of a DTS and replacement of the ISFSI and DTS occurs in an area with no historic or cultural resource present or construction occurs in a previously disturbed area that allows avoidance of historic and cultural resources, then impacts would be SMALL. By contrast, a MODERATE or LARGE impact could result if historic and cultural resources are present at a site and, because they cannot be avoided, are impacted by ground-disturbing activities during the long-term and indefinite timeframes.

Impacts on Federally listed species, designated critical habitat, and essential fish habitat would be based on site-specific conditions and determined as part of consultations required by the Endangered Species Act and the Magnuson-Stevens Fishery Conservation and Management Act.

Continued storage of spent nuclear fuel at an away-from-reactor ISFSI is not expected to cause disproportionately high and adverse human health and environmental effects on minority and low-income populations. As indicated in the Commission's policy statement on environmental justice, should the NRC receive an application for a proposed away-from-reactor ISFSI, a site-specific NEPA analysis would be conducted, and this analysis would include consideration of environmental justice impacts. Pursuant to 10 CFR 51.23, the impact determinations for away-from-reactor storage presented in NUREG-2157 are deemed incorporated into this SEIS.

4.13.1.5 Cumulative Impacts

NUREG-2157 examines the incremental impact of continued storage on each resource area analyzed in NUREG-2157 in combination with other past, present, and reasonably foreseeable future actions. NUREG-2157 indicates ranges of potential cumulative impacts for multiple resource areas (see Section 6.5 of NUREG-2157). However, these ranges are primarily driven by impacts from activities other than the continued storage of spent fuel at the reactor site; the impacts from these other activities would occur regardless of whether spent nuclear fuel is stored during the continued storage period. In the short-term timeframe, which is the most likely timeframe for the disposal of the fuel, the potential impacts of continued storage for at-reactor storage are SMALL and would, therefore, not be a significant contributor to the cumulative impacts. In the longer timeframes for at-reactor storage, or in the less likely case of away-from-reactor storage, some of the impacts from the storage of spent nuclear fuel could be greater than SMALL. As noted in NUREG-2157, other Federal and non-Federal activities occurring during the longer timeframes include uncertainties as well. It is primarily these uncertainties (i.e., those associated with activities other than continued storage) that contribute to the ranges of potential cumulative impacts discussed throughout Chapter 6 of NUREG-2157 and summarized in Table 6-4 of NUREG-2157. Because, as stated above, the impacts from these other activities would occur regardless of whether continued storage occurs, the overall cumulative impact conclusions in NUREG-2157 would still be the stated ranges regardless of whether there are impacts of continued storage from any individual licensing action.

Taking into account the impacts that the NRC considers most likely, which are SMALL; the uncertainty reflected by the ranges in some impacts; and the relative likelihood of the timeframes, the impact determinations for cumulative impacts presented in NUREG-2157 are deemed incorporated into this SEIS pursuant to 10 CFR 51.23.

4.13.1.6 Conclusion

Based on the information discussed above, the impacts of continued storage of spent nuclear fuel are those presented in NUREG-2157 and are deemed incorporated into this SEIS pursuant to 10 CFR 51.23. In addition, the revised 10 CFR 51.23 and NUREG-2157 have gone through the rulemaking process that involved significant input from the public. Therefore, the NRC staff concludes that the information in NUREG-2157 provides the appropriate NEPA analyses of the potential environmental impacts associated with the continued storage of spent fuel beyond the licensed life for reactor operations at Byron Station.

The NRC staff concludes that the revised 10 CFR 51.23, which adopts the generic impact determination regarding continued storage from NUREG-2157, satisfies the NRC's NEPA obligations with respect to continued storage of spent nuclear fuel, as it relates to the issues, "Onsite storage of spent nuclear fuel" and "Offsite radiological impacts of spent nuclear fuel and high-level waste disposal" for the environmental review associated the license renewal for Byron.

4.13.2 No-Action Alternative

If the no-action alternative were implemented, Byron would cease operation at the end of the initial operating licenses, or sooner, and enter decommissioning. The plants, which are currently operating within regulatory limits, would generate less spent nuclear fuel and emit less gaseous and liquid radioactive effluents into the environment. In addition, following shutdown, the variety of potential accidents at the plants (radiological and industrial) would be reduced to a limited set associated with shutdown events and fuel handling and storage. In Section 4.11 of this SEIS, the NRC staff concluded that the impacts of continued operations on human health would be SMALL. In Section 4.11 of this SEIS, the NRC staff concluded that the impacts of accidents would be SMALL. In Section 4.15.2 of this SEIS the NRC staff concludes that the impacts from decommissioning would be SMALL. Therefore, as radioactive emissions to the environment decrease, and the likelihood and variety of accidents decrease following shutdown and decommissioning, the NRC staff concludes that the risk to human health following plant shutdown would be SMALL.

4.13.3 New Nuclear Alternative

Construction-related debris would be generated during construction activities, and would be recycled or disposed of in approved landfills.

During normal plant operations, routine plant maintenance, and cleaning activities would generate radioactive low-level waste, spent nuclear fuel, and high-level waste as well as nonradioactive waste. Sections 3.1.4 and 3.1.5 discuss radioactive and nonradioactive waste management at Byron. Quantities of radioactive and nonradioactive waste generated by Byron would be comparable to that generated by the two new nuclear plants.

According to the GEIS (NRC 1996, 2013a), the generation and management of solid radioactive and nonradioactive waste during the license renewal term are not expected to result in significant environmental impacts.

Based on this information, the waste impacts would be SMALL for the new nuclear alternative.

4.13.4 IGCC Alternative

Construction-related debris would be generated during plant construction activities, and would be recycled or disposed of in approved landfills. The amount of the construction waste would be small compared to the amount of waste generated during the operational stage and much of it could be recycled (i.e., marketed for beneficial use).

Coal combustion generates waste in the form of fly ash and bottom ash. In addition, equipment for controlling air pollution generates additional ash, spent SCR catalyst, and scrubber sludge. The management and disposal of the large amounts of coal combustion waste is a significant part of the operation of a coal-fired power generating facility.

Although an IGCC facility is likely to use offsite disposal of coal combustion waste, some short-term storage of coal combustion waste (either in open piles or in surface impoundments) is likely to take place on site, thus establishing the potential for leaching of toxic chemicals into the local environment.

The impacts of managing the substantial amounts of solid waste, especially fly ash and scrubber sludge generated during operation of this alternative would be MODERATE (NRC 1996).

Therefore, the staff concludes that the overall waste management impacts from construction and operation of this alternative would be SMALL to MODERATE.

4.13.5 NGCC Alternative

Construction-related debris would be generated during plant construction activities, and would be recycled or disposed of in approved landfills.

Waste generation from NGCC technology would be minimal. The only significant waste generated at an NGCC power plant would be spent SCR catalyst, which is used to control nitrogen oxide emissions.

The spent catalyst would be regenerated or disposed of off site. Other than spent SCR catalyst, waste generation at an operating natural gas-fired plant would be limited largely to typical operations and maintenance nonhazardous waste. Overall, the NRC staff concludes that waste impacts from the NGCC alternative would be SMALL.

4.13.6 Combination Alternative (NGCC, Wind, Solar)

Construction-related debris would be generated during construction activities, and would be recycled or disposed of in approved landfills.

Waste generation from NGCC technology would be minimal. The only significant waste generated at an NGCC power plant would be spent SCR catalyst, which is used to control nitrogen oxide emissions.

Waste generation from a combination of wind and solar PV alternatives would be minimal, consisting of debris from routine maintenance and the disposal of worn or broken parts. Based on this information, the NRC staff concludes that waste impacts from the construction and operation of a combination wind and solar PV alternative would be SMALL.

4.13.7 Purchased Power

The types of waste generated by the alternative electricity generation sources (i.e., coal, natural gas, nuclear, and wind) used in the purchased power alternative are discussed in Sections 4.13.3, 4.13.4, 4.13.5, and 4.13.6. Depending on types of power-generation plants used to provide the electricity for the purchased power alternative, the NRC staff concludes that the waste management impacts would range from SMALL to MODERATE.

4.14 Evaluation of New and Potentially Significant Information

New and significant information is information that must be new, based on a review of the GEIS (NRC 2013a) and codified in Table B-1 of 10 CFR Part 51, Subpart A, Appendix B, and must bear on the proposed action or its impacts, presenting a seriously different picture of the impacts from those envisioned in the GEIS (i.e., impacts of greater severity than impacts considered in the GEIS, considering their intensity and context).

In accordance with 10 CFR 51.53(c), the ER that the applicant submits must provide an analysis of the Category 2 issues in Table B-1 of 10 CFR Part 51, Subpart A, Appendix B. Additionally, it must discuss actions to mitigate any adverse impacts associated with the proposed action and environmental impacts of alternatives to the proposed action. In accordance with 10 CFR 51.53(c)(3), the ER does not need to contain an analysis of any Category 1 issue unless there is new and significant information on a specific issue.

The NRC process for identifying new and significant information is described in NUREG–1555, Supplement 1, *Standard Review Plans for Environmental Reviews for Nuclear Power Plants, Supplement 1: Operating License Renewal* (NRC 1999, 2013ai). The search for new information includes:

- review of an applicant's ER and the process for discovering and evaluating the significance of new information;
- review of public comments;
- review of environmental quality standards and regulations;

- coordination with Federal, state, local, and tribal environmental protection and resource agencies; and
- review of the technical literature.

New information that the staff discovers is evaluated for significance using the criteria set forth in the GEIS. For Category 1 issues in which new and significant information is identified, reconsideration of the conclusions for those issues is limited in scope to assessment of the relevant new and significant information; the scope of the assessment does not include those facets of an issue that are not affected by the new information.

The NRC staff reviewed the discussion of environmental impacts associated with operation during the renewal term in the GEIS and has conducted its own independent review, including a public involvement process (e.g., public meetings) to identify new and significant issues for the Byron license renewal application environmental review. The NRC staff has not identified new and significant information on environmental issues related to operation of Byron during the renewal term. The NRC staff also determined that information provided during the public comment period did not identify any new issue that requires site-specific assessment.

4.15 Impacts Common to All Alternatives

This section describes the impacts that are considered common to all alternatives discussed in this SEIS, including the proposed action and replacement power alternatives. The continued operation of a nuclear power plant and replacement fossil fuel power plants both involve mining, processing, and the consumption of fuel, which results in comparative impacts (NRC 2013a). The termination of operations and the decommissioning of both a nuclear power plant and replacement fossil fueled power plants are also discussed in the following sections, as well as GHG emissions.

4.15.1 Fuel Cycle

This section describes the environmental impacts associated with the fuel cycles of the proposed action and replacement power alternatives. Most replacement power alternatives employ a set of steps in the utilization of their fuel sources, which can include extraction, transformation, transportation, and combustion. Emissions generally occur at each stage of the fuel cycle (NRC 2013a).

4.15.1.1 Uranium Fuel Cycle

The uranium fuel cycle issues applicable to Byron are discussed below and listed in Table 4–19 for Category 1 issues. Table B-1 of Appendix B to Subpart A of 10 CFR Part 51 contains more information on these issues.

Table 4–19. Issues Related to the Uranium Fuel Cycle

Issue	GEIS Section	Category
Offsite radiological impacts—individual impacts from other than the disposal of spent fuel and high-level waste	4.12.1.1	1
Office radiological impacts—collective impacts from other than the disposal of spent fuel and high-level waste	4.12.1.1	1
Nonradiological impacts of the uranium fuel cycle	4.12.1.1	1
Transportation	4.12.1.1	1

Source: Table B-1 in Appendix B, Subpart A, to 10 CFR Part 51

The uranium fuel cycle includes uranium mining and milling, the production of uranium hexafluoride, isotopic enrichment, fuel fabrication, reprocessing of irradiated fuel, transportation of radioactive materials, and management of low-level wastes and high-level wastes related to uranium fuel cycle activities. The generic potential impacts of the radiological and nonradiological environmental impacts of the uranium fuel cycle and transportation of nuclear fuel and wastes are described in detail in NUREG–1437, *Generic Environmental Impact Statement* (GEIS) *for License Renewal of Nuclear Plants* (NRC 1996, 1999, 2013a).

The NRC staff did not identify any new and significant information related to the uranium fuel cycle issues listed in Table 4–19 during its review of the applicant's ER (Exelon 2013a), the site visit, and the scoping process. Therefore, there are no impacts related to these issues beyond those discussed in the GEIS. For these Category 1 issues, the GEIS concludes that the impacts are SMALL, except for the issue, "Offsite radiological impacts—collective impacts," to which the NRC has not assigned an impact level. This issue assesses the 100-year radiation dose to the U.S. population (i.e., collective effects or collective dose) from radioactive effluent released as part of the uranium fuel cycle for a nuclear power plant during the license renewal term compared to the radiation dose from natural background exposure. It is a comparative assessment for which there is no regulatory standard to base an impact level.

4.15.1.2 Replacement Power Plant Fuel Cycles

<u>Fossil Fuel Energy Alternatives</u>

Fuel cycle impacts for a fossil-fuel-fired plant result from the initial extraction of fuel, cleaning and processing of fuel, transport of fuel to the facility, and management and ultimate disposal of solid wastes from fuel combustion. These impacts are discussed in more detail in Section 4.12.1.2 of the GEIS (NRC 2013a) and can generally include:

- significant changes to land use and visual resources;
- impacts to air quality, including release of criteria pollutants, fugitive dust, VOCs, and coalbed methane in the atmosphere;
- noise impacts;
- geology and soil impacts due to land disturbances and mining;
- water resource impacts, including degradation of surface water and groundwater quality;
- ecological impacts, including loss of habitat and wildlife disturbances;
- historic and cultural resources impacts within the mine footprint;

- socioeconomic impacts from employment of both the mining workforce and service and support industries;
- environmental justice impacts;
- health impacts to workers from exposure to airborne dust and methane gases; and
- generation of coal and industrial wastes.

New Nuclear Energy Alternatives

Fuel cycle impacts for a nuclear plant result from the initial extraction of fuel, transport of fuel to the nuclear plant, and management and ultimate disposal of spent fuel. The environmental impacts of the uranium fuel cycle are discussed above, in Section 4.15.1.1.

Renewable Energy Alternatives

The term "fuel cycle" has varying degrees of relevance for renewable energy facilities. The term has meaning for renewable energy technologies that rely on combustion of fuels such as biomass grown or harvested for the express purpose of power production. The term is somewhat more difficult to define for renewable technologies such as wind, solar, geothermal, and ocean wave and current. Those natural energy resources exist regardless of any effort to harvest them for electricity production. The common technological strategy for harvesting energy from such natural resources is to convert the kinetic or thermal energy inherent in that resource to mechanical energy or torque. The torque is then applied directly (e.g., as in the case of a wind turbine) or indirectly (e.g., for those facilities that use conventional steam cycles to drive turbines that drive generators) to produce electricity. However, because those renewable technologies capture very small fractions of the total kinetic or thermal energy contained in those resources, impacts from the presence or absence of the renewable energy technology are often indistinguishable (NRC 2013a).

4.15.2 Terminating Power Plant Operations and Decommissioning

This section describes the environmental impacts associated with the termination of operations and the decommissioning of a nuclear power plant and replacement power alternatives. All operating power plants will terminate operations and be decommissioned at some point after the end of their operating life or after a decision is made to cease operations. For the proposed action, license renewal would delay this eventuality for an additional 20 years beyond the current license period, which ends in 2024 and 2026 for Byron Units 1 and 2, respectively.

4.15.2.1 Existing Nuclear Power Plant

Environmental impacts from the activities associated with the decommissioning of any reactor before or at the end of an initial or renewed license are evaluated in Supplement 1 of NUREG–0586, *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities Regarding the Decommissioning of Nuclear Power Reactors* (NRC 2002). Additionally, the incremental environmental impacts associated with decommissioning activities resulting from continued plant operation during the renewal term are discussed in the GEIS.

Table 4–20 lists the Category 1 issues in Table B-1 of Title 10 of the CFR Part 51, Subpart A, Appendix B that are applicable to Byron decommissioning following the license renewal term.

Table 4–20. Issues Related to Decommissioning

Issue	GEIS Section	Category
Radiation doses	4.12.2.1	1
Waste management	4.12.2.1	1
Air quality	4.12.2.1	1
Water quality	4.12.2.1	1
Ecological resources	4.12.2.1	1
Socioeconomic impacts	4.12.2.1	1

Source: Table B-1 in Appendix B, Subpart A, to 10 CFR Part 51

Decommissioning would occur whether Byron were shut down at the end of its current operating license or at the end of the period of the license renewal term. Exelon stated in its ER (Exelon 2013a) that it is not aware of any new and significant information on the environmental impacts of Byron during the license renewal term. The NRC staff has not found any new and significant information during its independent review of Exelon's ER, the site visit, or the scoping process. Therefore, the NRC staff concludes that there are no impacts related to these issues, beyond those discussed in the GEIS. For all of these issues, the NRC staff concluded in the GEIS that the impacts are SMALL.

4.15.2.2 Replacement Power Plants

Fossil Fuel Energy Alternatives

The environmental impacts from the termination of power plant operations and decommissioning of a fossil-fuel-fired plant are dependent on the facility's decommissioning plan. General elements and requirements for a fossil fuel plant decommissioning plan are discussed in Section 14 of the GEIS and can include the removal of structures to at least 3 ft (1 m) below grade, removal of all coal, combustion waste, and accumulated sludge, removal of intake and discharge structures, and the cleanup and remediation of incidental spills and leaks at the facility. The decommissioning plan outlines the actions necessary to restore the site to a condition equivalent in character and value to the site on which the facility was first constructed (NRC 2013a).

The environmental consequences of decommissioning are discussed in Section 4.12.2.2 of the GEIS and can generally include:

- short-term impacts on air quality and noise from the deconstruction of facility structures,
- short-term impacts on land use and visual resources,
- long-term reestablishment of vegetation and wildlife communities,
- socioeconomic impacts due to decommissioning workforce and the long-term loss of jobs, and
- elimination of health and safety impacts on operating personnel and general public.

New Nuclear Alternatives

Termination of operations and decommissioning impacts for a nuclear plant include all activities related to the safe removal of the facility from service and the reduction of residual radioactivity to a level that permits release of the property under restricted conditions or unrestricted use and termination of a license (NRC 2013a). The environmental impacts of the uranium fuel cycle are discussed above, in Section 4.15.1.1.

Renewable Alternatives

Termination of power plant operation and decommissioning for renewable energy facilities would be similar to the impacts discussed for fossil-fuel-fired plants above. Decommissioning would involve the removal of facility components and operational wastes and residues in order to restore the site to a condition equivalent in character and value to the site on which the facility was first constructed (NRC 2013a).

4.15.3 Greenhouse Gas Emissions and Climate Change

The following sections discuss GHG emissions released from operation of Byron Station and the environmental impacts that could occur from changes in climate conditions. The cumulative impacts of GHG emissions on climate are discussed in Section 4.16.11, Global Climate Change.

4.15.3.1 Greenhouse Gas Emissions From the Proposed Project and Alternatives

Gases found in the Earth's atmosphere that trap heat and play a role in Earth's climate are collectively termed GHGs. GHGs include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), water vapor (H_2O), and fluorinated gases such as hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Earth's climate responds to changes in concentration of GHG in the atmosphere as GHGs affect the amount of energy absorbed and heat trapped by the atmosphere. Increasing GHG concentration in the atmosphere generally increases Earth's surface temperature. Atmospheric concentrations of carbon dioxide, methane, and nitrous oxide have significantly increased since 1750 (Solomon et al. 2007). Carbon dioxide, methane, nitrous oxide, HFCs, PFCs, and sulfur hexafluoride (termed long-lived GHGs) are well-mixed throughout Earth's atmosphere and their impact on climate is long-lasting as a result of their long atmospheric lifetime (EPA 2009b). Carbon dioxide is of primary concern for global climate change due to its long atmospheric lifetime, and it is the primary gas emitted as a result of human activities. Climate change research indicates that the cause of the Earth's warming over the last 50 years is due to the buildup of GHGs in atmosphere resulting from human activities (Melillo et al. 2014).

Proposed Action

Plant operations at Byron Station release GHG emissions (primarily carbon dioxide) from stationary combustion sources, such as standby emergency diesel generators, auxiliary boilers, auxiliary feedwater (AFW) pumps, SX makeup water pumps, and a fire pump. Other sources include mobile combustion sources (e.g., compressors, generators) and vehicle traffic (such as workers and delivery). Fluorinated gases are used as the refrigerant in air conditioning and refrigeration systems and in electrical transmission and distribution systems. These fluorinated gases are typically emitted in small quantities but their impacts could be substantial because of high global warming potential.

The GHG emissions generated directly and indirectly by an entity can be classified into three "Scopes," based on the source of the emissions (EPA 2013a). Scope 1 GHG emissions are direct emissions that are owned or controlled by the entity, which include emissions from fossil fuels burned on site, emissions from entity-owned or entity-leased vehicles, and other direct sources. Scope 2 GHG emissions are indirect emissions resulting from the generation of electricity, heating/cooling, or steam generated off site but purchased by the reporting entity. Scope 3 GHG emissions are indirect emissions from sources not owned or directly controlled by the reporting entity but related to the entity's activities such as vendor supply chains, delivery services, outsourced activities, and employee travel and commuting. GHG emissions from nuclear power plants including Byron Station belong to all three Scopes. Annual total GHG emissions at Byron Station are presented in Table 4–21 for the 2008 to 2012 period. Direct emissions include permitted combustion sources only, which are reported to the IEPA per the requirements of 35 IAC Part 254 (Exelon 2009, 2010, 2011, 2012, 2013c). Total (direct plus indirect) GHG emissions include permitted combustion sources (diesel generators and auxiliary boilers), fugitive gas emissions, direct fluorinated gases, indirect purchased electricity, and ozone depleting substances from refrigerants. However, total emissions do not include GHG emissions from mobile sources because Exelon does not compile site-specific data for such sources (Exelon 2013b). The NRC staff estimates annual GHG emission resulting from employee vehicles to be approximately 8,400 MT CO_2e.

Table 4–21. Estimated GHG Emissions From Operations at Byron Station

Year	CO_2e (MT/year)
2008	12,102
2009	10,872
2010	12,059
2011	12,017
2012	13,962

Source: Exelon 2013b

No-Action Alternative

As discussed in previous no-action alternative sections, the no-action alternative represents a decision by the NRC not to renew the operating license of a nuclear power plant beyond the current operating license term. At some point, all nuclear plants will terminate operations and undergo decommissioning. Under the no-action alternative, plant operations for Byron would terminate at or before the end of the current license term (NRC 2013a). When the plant stops operating, there will be a reduction in GHG emissions from activities related to plant operation, such as use of diesel generators and employee vehicles. GHG emissions are anticipated to be less than what is presented in Table 4–21.

New Nuclear Alternative

As discussed in Section 2.2.2.2, the NRC staff evaluated the new nuclear power plant alternative that would consist of two units with an approximate generating capacity of 1,120 MWe each. The GEIS presents life-cycle GHG emissions associated with nuclear power generation. As presented in Tables 4.12-4 through 4.12-6 of the GEIS, life-cycle[13] GHG emissions from nuclear power generation can range from 1 to 288 g carbon equivalent per kilowatt-hour (C_{eq}/kWh). Operation of nuclear power plants does not burn fossil fuels to

[13]Life-cycle carbon emissions analyses consider construction, operation, decommissioning, and associated processing of fuel (gas, coal, etc.).

generate electricity and so does not directly emit GHG emissions. Sources of GHG emissions include stationary combustion sources (e.g., emergency diesel generators, diesel-driven fire pumps, auxiliary boilers) and mobile sources (worker vehicles, onsite heavy equipment and support vehicles, and delivery of materials and disposal of wastes). As discussed in Section 4.3.3.1, it is anticipated that air emissions from a new nuclear power plant would be similar to those from Byron.

IGCC Generation Alternative

As discussed in Section 2.2.2.2, the NRC staff evaluated the IGCC plant alternative that would consist of four units with a total output of 2,472 MW.

The IGCC alternative would release GHGs. The NRC staff estimates that operation of four IGCC units will directly emit about 14.3 million t (approximately 12.9 million MT) per year of CO_2e.

Emissions were estimated for the IGCC alternative without CCS. Among the alternatives, GHG emissions are the highest from IGCC plants. As described in Chapter 2, the IGCC alternative assumes that the plants may install CCS technology at some point in the future, which would reduce carbon dioxide emissions considerably. The DOE's National Energy Technology Laboratory (NETL) performed a study to establish the cost and performance for a range of carbon dioxide capture levels (up to 97 percent) for new IGCC power plants (NETL 2013a). The study identified technical configurations that were tailored to achieve a specific level of carbon capture.

NGCC Generation Alternative

As discussed in Section 2.2.2.3, the NRC staff evaluated an NGCC alternative that consists of five NGCC 560-MWe units (total 2,800 MWe). The GEIS presents life-cycle GHG emissions associated with natural gas power generation. As presented in Table 4.12-5 of the GEIS, life-cycle GHG emissions from natural gas can range from 120 to 930 g C_{eq}/kWh. The NRC staff estimates that operation of the NGCC alternative directly will emit about 7.9 million t (approximately 7.2 million MT) per year of CO_2e emissions.

Combination Alternative (NGCC, Wind, and Solar)

For this combination alternative, it is assumed that the majority of the GHG emissions result from the NGCC portion only because renewable portions (wind and solar PV) do not burn fossil fuels to generate electricity. As discussed in Section 4.3.6.1, GHG emissions associated with the operation of the NGCC portion are reduced proportionally because its electricity output is approximately 13 percent that of the NGCC alternative. The NRC staff estimates that operation of the combination alternative will directly emit 1.0 million t (0.9 million MT) per year of CO_2e.

Purchased Power Alternative

Purchased power would come from common types of existing technology (coal, natural gas, nuclear, and renewable sources) within the ROI and it is not likely that new facilities would be constructed to replace Byron. GHG emissions from purchased power will vary and depend on the type and combination of technology purchased power comes from. In 2012, coal, natural gas, and nuclear power accounted for 37-, 30-, and 19-percent share, respectively, of total U.S. electricity generation (EIA 2014). Using these percent shares for the purchased power alternative, the NRC staff estimates 7.7 million t (6.9 million MT) per year of CO_2e will be emitted. However, GHG emissions may be greater or less than this estimate and will depend on the technology from which the purchased power comes.

Summary of GHG Emissions From the Proposed Action and Alternatives

Table 4–22 presents the direct uncontrolled GHG emissions from operation of the proposed action and alternatives. GHG emissions from the proposed action (continued operation at Byron) and the new nuclear alternative would be lowest. GHG emissions for IGCC, NGCC, combination, and purchased power alternatives are higher than those for the proposed action and a new nuclear alternative by several orders of magnitude. GHG emissions for purchased power are expected to be greater than the NGCC alternative, but less than the IGCC alternative.

Table 4–22. Direct Uncontrolled GHG Emissions From Operation of the Proposed Action and Alternatives

Technology	CO_2e (MT/year)
Byron Station continued operation	1.363×10^{3}
New Nuclear	1.363×10^{3}
IGCC	13.0×10^{6}
NGCC	7.2×10^{6}
Combination [(a)]	1.0×10^{6}
Purchased Power [(b)]	6.9×10^{6}

[(a)] Only NGCC portion of GHG emissions

[(b)] Assumed air emissions were estimated by assuming that purchased-power coal accounted for 37 percent share, natural gas a 30 percent share, nuclear a 19 percent share, and renewable a 14 percent share of electricity generation.

4.15.3.2 Climate Change Impacts to Resource Areas

Climate change is the decades or longer change in climate measurements (temperature, precipitation, etc.) that has been observed on a global, national, and regional level (EPA 2012a; Melillo et al. 2014; Solomon et al. 2007). Climate change can vary regionally, spatially, and seasonally depending on local, regional, and global factors. Just as the regional climate differs throughout the world, the impacts of climate change can vary between locations.

On a global level, from 1901 to 2011, average surface temperatures have risen at a rate of 0.08 °C (0.14 °F) per decade, and total annual precipitation has increased at an average rate of 2.3 percent per decade (EPA 2012a). The observed global change in average surface temperature and precipitation has been accompanied by an increase in sea surface temperatures, a decrease in global glacier ice, increase in sea level, and changes in extreme weather events. Such extreme events include an increase in frequency of heat waves, heavy precipitation, and minimum and maximum temperatures (EPA 2012a; Karl et al. 2009; Melillo et al. 2014; Solomon et al. 2007).

In the United States, the U.S. Global Change Research Program (USGCRP) reports that from 1895 to 2012, average surface temperature has increased by 1.3 °F to 1.9 °F (0.72 to 1.06 °C) and since 1900, average annual precipitation has increased by 5 percent (Melillo et al. 2014). On a seasonal basis, warming has been the greatest in winter and spring. From 1895 to 2001, an increase in the length of the freeze-free season, the period between the last occurrence of 0 °C (32 °F) in the spring and first occurrence of 0 °C (32 °F) in the fall has been observed for the contiguous United States; between 1991 and 2011 the average freeze-free season was 10 days longer than between 1901 and 1960 (Melillo et al. 2014). Since the 1970s, the United States has warmed at a faster rate as the average surface temperature rose at an average rate of 0.17 to 0.25 °C (0.31 to 0.45 °F) per decade. In addition, the year 2012 was the warmest on record (Melillo et al. 2014). Observed climate-related changes in the United States include increases in the frequency and intensity of heavy precipitation, earlier onset of spring snowmelt and runoff, rise of sea level in coastal areas of the United States, increase in occurrence of heat waves, and a decrease in occurrence of cold waves (EPA 2012a; Karl et al. 2009; Kunkel et al. 2013b; Melillo et al. 2014).

Temperature data indicate that the Midwest region, where Byron is located, experienced a 0.06 °C (0.11 °F) per decade increase in annual mean temperature during the 1900 to 2010 period (Kunkel et al. 2013a). Temperature data for the recent past indicate an increased rate of warming for the Midwest: 0.12 °C (0.22 °F) per decade for the 1950 to 2010 time period and a 0.26 °C (0.47 °F) temperature increase for the 1979 to 2010 time period. Average annual precipitation data for the Midwest exhibit an increasing trend of 0.31 in. per decade for the long-term period (1895 to 2011) (Kunkel et al. 2013a). Precipitation data over the 1958 to 2007 period exhibit clear trends toward more very-heavy precipitation events (defined as the heaviest 1 percent of all daily events) for the Nation as a whole, and particularly in the Northeast and Midwest. Temperature and precipitation trends were analyzed for the period of 1961 to 2012 at the Rockford Airport (NCDC 1984, 2013). Although there are large year-to-year variations, a clear upward trend in temperature and a downward trend in precipitation are observed. At Byron, for the 1973 to 2013 period, an upward trend in ambient annual average temperature has also been observed (Exelon 2013b).

Future GHG emission concentration and climate models are commonly used to project possible climate change. Climate models indicate that over the next few decades, temperature increases will continue due to current GHG emissions concentrations in the atmosphere (Melillo et al. 2014). Over the longer term, the magnitude of temperature increases and climate change effects will depend on both past and future GHG emission scenarios (Karl et al. 2009; Melillo et al. 2014; Solomon et al. 2007). Climate models project a continued increase in global surface temperatures, more frequent and long-lasting heat waves, continued increase in sea level, continued decline in arctic sea ice, an increase in heavy precipitation events, and an increased frequency of severe droughts.

For the license renewal period of Byron, climate model simulations (between 2021 and 2050 relative to the reference period (1971 to 1999)) indicate an increase in annual mean temperature in the Midwest region from 2.5 to 3.5 °F (1.5 to 2.1 °C) (Kunkel et al. 2013a). The predicted increase in temperature during this time period occurs for all seasons with the largest increase occurring in the summertime (June, July, and August). Models project an increase in summertime mean temperatures of 3 °F (1.6 °C); however, climate models displayed a wide range in summertime temperatures, ranging from an increase of 1.5 to 5.5 °F (0.76 to 2.98 °C) (Kunkel et al. 2013a). Climate model simulations (for the time period 2021 to 2050) suggest spatial differences in annual mean precipitation changes for the Midwest with northern areas experiencing an increase in precipitation and the southern areas experiencing a decrease in precipitation. For Illinois, the models indicate a 0 to 3 percent increase in annual mean precipitation with fall, winter, and spring seasons experiencing precipitation change increases and the summer season experiencing a decrease in precipitation. However, these changes in precipitation were not significant and the models indicate changes that are less than normal year-to-year variations (Kunkel et al. 2013a). While future regional changes in precipitation are difficult to predict, the USGCRP reports that storm tracks are expected to shift northward, increases in heavy precipitation events will continue, the number of dry days between rainfalls will increase, and an increase in drought are expected (Melillo et al. 2014).

Changes in climate have broader implications for public health, water resources, land use and development, and ecosystems. For instance, changes in precipitation patterns and increase in air temperature can affect water availability and quality, distribution of plant and animal species, and land-use patterns and land cover, which can in turn affect terrestrial and aquatic habitats. The following sections discuss how future climate change may impact air quality, water resources, land use, terrestrial resources, aquatic resources, and human health in the region of interest for Byron Station. Although there is uncertainty in the exact future climate change scenario, the discussions provided below demonstrate the potential implications of climate change on resources.

Air Quality

Air pollutant concentrations result from complex interactions between physical and dynamic properties of the atmosphere, land, and ocean. The formation, transport, dispersion, and deposition of air pollutants depend in part on weather conditions (Parry et al. 2007). Air pollutant concentrations are sensitive to winds, temperature, humidity, and precipitation (EPA 2009b). Hence, climate change can impact air quality as a result of the changes in meteorological conditions.

Ozone has been found to be particularly sensitive to climate change (EPA 2009a; Melillo et al. 2014; Parry et al. 2007). Ozone is formed as a result of the chemical reaction of nitrogen oxides and VOCs in the presence of heat and sunlight. Sunshine, high temperatures, and air stagnation are favorable meteorological conditions to higher levels of ozone (EPA 2009a; Parry et al. 2007). The emission of ozone precursors also depends on temperature, wind, and solar radiation (Parry et al. 2007); both nitrogen oxide and biogenic VOC emissions are expected to be higher in a warmer climate (EPA 2009a). Warmer climate and weaker air circulation are conducive to higher ozone levels. Regional air quality modeling indicates that the northern regions of the United States can experience an increase in ozone concentration by the year 2050 (Tagaris et al. 2009). However, air quality projections (particularly ozone and particulate matter with aerodynamic diameters of 2.5 μm or less ($PM_{2.5}$)) are uncertain and indicate that concentrations are driven primarily by emissions rather than by physical climate change (Stocker et al. 2013). The combination of higher temperatures, stagnant air masses, sunlight, and emissions of precursors may make it difficult to meet ozone NAAQS (Karl et al. 2009).

Land Use

Anthropogenic land use is both a contributor to climate change as well as a receptor of climate change impacts (Dale 1997). As described previously in this section, the Midwest will likely experience rising temperatures and heavier precipitation events during the proposed license renewal period. Agriculture (the major land use in the vicinity of Byron) and growing urban areas will further exacerbate these changes by continuing to inhibit natural ecosystem functions that could moderate climate change effects. For instance, air temperatures and near-surface moisture levels change in areas where natural vegetation is converted to agricultural use, and in the Midwest, higher temperatures have been observed as a result of converting land to agricultural use (Melillo et al. 2014). The USGCRP (Melillo et al. 2014) indicates that land use changes, such as the continued expansion of urban areas, paired with climate change effects, such as heaver precipitation events, can exacerbate climate change effects, including reduced water filtration into the soil and increased surface runoff. While anthropogenic land uses will contribute to climate change in these and other ways, land uses will also be affected by climate change in several ways. For instance, plant winter hardiness zones are likely to shift one-half to one full zone by the end of the proposed license renewal period (Melillo et al. 2014). This will affect the ability to grow certain crops as the Midwest will likely contain plants now associated with the Southeast by the end of the century (Melillo et al. 2014). Water availability will likely affect urban areas, which are growing rapidly in the Midwest. This growth will likely lead to water use conflicts as climate change reduces water availability and the growing population requires more water.

Water Resources

Predicted changes in the timing, intensity, and distribution of precipitation would be likely to result in changes in surface water runoff affecting water availability across the Midwest. As discussed above, the Midwest may experience increased precipitation during the fall, winter, and spring. As cited by the USGCRP, the loss of moisture from soils because of higher temperatures, as is projected for the Midwest, along with evapotranspiration from vegetation, is likely to increase the frequency, duration, and intensity of droughts across the region into the future (Karl et al. 2009; Melillo et al. 2014); such conditions can reduce the amount of water available for surface runoff and streamflow. Runoff and streamflow at a regional scale for the Midwest region indicate no clear trend during the last half century. However, annual runoff and river flow are projected to increase in the upper Midwest, and soil moisture has increased in most seasons in the upper Midwest between 1998 and 2010 (Melillo et al. 2014). Climate change impacts on groundwater availability depends on basin geology, frequency and intensity of high-rainfall periods, recharge, soil moisture, and groundwater–surface water interactions (Melillo et al. 2014). Precipitation and evapotranspiration are key drivers in aquifer recharge. Although exact responses in groundwater storage and flow to climate change are not well-understood, recent studies have started to consider the effects that climate change has on groundwater resources (Melillo et al. 2014).

Terrestrial Resources

As described above, the Midwest will likely experience rising temperatures and heavier precipitation events during the proposed license renewal period. As the climate changes, terrestrial resources will either need to be able to tolerate the new physical conditions or shift their population range to new areas with a more suitable climate. Scientists currently estimate that species are shifting their ranges at a rate of between 6.1 to 11 m (20 to 36 ft) in elevation per decade and 6.1 to 16.9 km (3.8 to 10.5 mi) in latitude per decade (Chen et al. 2011; Thuiller 2007). While some species may readily adapt to a changing climate, others may be more prone to experience adverse effects. For example, species whose ranges are already limited by habitat loss or fragmentation or who require very specific environmental conditions may not be able to successfully shift their ranges over time. Migratory birds that travel long distances may also be disproportionately affected because they may not be able to pick up on environmental cues that a warmer, earlier spring is occurring in the United States while overwintering in tropical areas. Fraser et al. (2013) found that songbirds overwintering in the Amazon did not leave their winter sites earlier, even when spring sites in the Eastern United States experienced a warmer spring. As a result, the songbirds missed periods of peak food availability. Habitat ranges for forest systems in the Midwest, such as paper birch, balsam fir, and black spruce, are projected to decline across the Midwest as they shift northward, and species that are common farther south, such as oaks and pines, will expand their range north into the Midwest region (Melillo et al. 2014). Special status species and habitats, such as those that are Federally protected by the ESA, would likely be more sensitive to climate changes because these species' populations are already experiencing threats that are endangering their continued existence throughout all or a significant portion of their ranges. Climate changes could also favor nonnative, invasive species and promote population increases of insect pests and plant pathogens, which may be more tolerant to a wider range of climate conditions.

Aquatic Resources

The potential effects of climate change, whether from natural cycles or manmade activities could result in changes that would affect aquatic resources in the Rock River. Raised air temperatures could result in higher water temperatures in the Rock River and its tributaries. Higher water temperatures would increase the potential for thermal effects on aquatic biota and could exacerbate existing environmental stressors, such as excess nutrients, sedimentation, and lowered dissolved oxygen associated with eutrophication (Melillo et al. 2013). The Midwest will likely experience increased frequency of extreme rainfall events, which will cause erosion and could lead to a decline in water quality (Melillo et al. 2014). Species that require cleaner waters, such as freshwater mussels, could experience further population declines. The USGCRP (Melillo et al. 2014) predicts habitat loss and local extinctions of fish and other aquatic species throughout the United States from the combined effects of water withdrawal and climate change. Shifts in species' assemblages and distributions are also likely as climate change continues (Melillo et al. 2014), and these shifts could alter the balance of the aquatic community in the Rock River. As discussed above under "Terrestrial Resources," special status species, such as those that are Federally protected under the ESA, would be more sensitive to climate changes. Invasions of nonnative species that thrive under a wide range of environmental conditions could further disrupt the current composition of aquatic communities (NRC 2013a).

Historic and Cultural Resources

Increases in river and lake water levels because of changes in meteorological conditions due to climate change could result in the loss of historic and cultural resources from flooding, erosion, or inundation. Due to water-level changes, some resources could be lost before they could be documented or otherwise studied. However, the limited extent of climate change that may occur during the 20-year license renewal term would not likely result in any significant loss of historic and cultural resources at Byron.

Socioeconomics

Rapid changes in climate conditions could have an impact on the availability of jobs in certain industries. For example, tourism and recreation are major job creators in some regions, bringing billions of dollars to regional economies. Across the Nation, fishing, hunting, and other outdoor activities make important economic contributions to rural economies and are also a part of the cultural tradition. A changing climate would mean reduced opportunities for some activities in some locations and expanded opportunities for others. Hunting and fishing opportunities could also change as animals' habitats shift and as relationships among species are disrupted by their different responses to climate change (Melillo et al. 2014). Water-dependent recreation could also be affected (Karl et al. 2009;). The USGCRP reports that increasing heat and humidity associated with climate change in parts of the Midwest region by the year 2050 could create unfavorable conditions for summertime outdoor recreation and tourism activity (Melillo et al. 2014). However, the limited extent of climate change that may occur during the 20-year license renewal term would not be likely to cause any significant changes in socioeconomic conditions in the vicinity of Byron.

Human Health

Increasing temperatures due to changes in climate conditions could have an impact on human health. However, changes in climate conditions that may occur during the license renewal term will not result in any change to the impacts discussed in Section 4.11 from Byron's radioactive and nonradioactive effluents.

Environmental Justice

Rapid changes in climate conditions could disproportionately affect minority and low-income populations. The USGCRP (Karl et al. 2009) indicates that "infants and children, pregnant women, the elderly, people with chronic medical conditions, outdoor workers, and people living in poverty are especially at risk from a variety of climate-related health effects." Examples of these effects include increased heat stress, air pollution, extreme weather events, and diseases carried by food, water, and insects. The greatest health burdens related to climate change are likely to fall on the poor, especially those lacking adequate shelter and access to other resources such as air conditioning. Elderly people on fixed incomes, who are more likely to be poor, are more likely to have debilitating chronic diseases or limited mobility. In addition, the elderly have a reduced ability to regulate their own body temperature or sense when they are too hot. According to the USGCRP (Karl et al. 2009), they "are at greater risk of heart failure, which is further exacerbated when cardiac demand increases in order to cool the body during a heat wave." The USGCRP study also found that people taking medications, such as diuretics for high blood pressure, have a higher risk of dehydration (Karl et al. 2009). The USGCRP (Melillo et al. 2014) study reconfirmed the previous report findings regarding the risks of climate change on low-income populations, and also warns that climate change could affect the availability and access to local plant and animal species, thus impacting the people that have historically depended on them for food or medicine (Melillo et al. 2014). However, due to the amount of expected change in the environment during the 20-year license renewal term, minority and low-income populations at Byron are not likely to experience disproportionately high and adverse impacts from climate change.

4.16 Cumulative Impacts of the Proposed Action

The NRC staff considered potential cumulative impacts in the environmental analysis of continued operation Byron during the 20-year license renewal period. Cumulative impacts may result when the environmental effects associated with the proposed action are overlaid or added to temporary or permanent effects associated with other past, present, and reasonably foreseeable actions. Cumulative impacts can result from individually minor, but collectively significant, actions taking place over a period of time. It is possible that an impact that may be SMALL by itself could result in a MODERATE or LARGE cumulative impact when considered in combination with the impacts of other actions on the affected resource. Likewise, if a resource is regionally declining or imperiled, even a SMALL individual impact could be important if it contributes to or accelerates the overall resource decline.

For the purposes of this cumulative analysis, past actions are those before the receipt of the license renewal application. Present actions are those related to the resources at the time of current operation of the power plant, and future actions are those that are reasonably foreseeable through the end of plant operation, including the period of extended operation. Therefore, the analysis considers potential impacts through the end of the current license terms as well as the 20-year renewal license term. The geographic area over which past, present, and reasonably foreseeable actions would occur depends on the type of action considered and is described below for each resource area.

To evaluate cumulative impacts, the incremental impacts of the proposed action, as described in Sections 4.2 to 4.15, are combined with other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such actions. The NRC staff used the information provided in Exelon's ER; responses to requests for additional information; information from other Federal, State, and local agencies; scoping comments; and information gathered during the visits to the Byron site to identify other past, present, and reasonably foreseeable actions. To be considered in the cumulative analysis, the NRC staff determined if the project would occur within the noted geographic areas of interest and within the period of extended operation, was reasonably foreseeable, and if there would be a potential overlapping effect with the proposed project. For past actions, consideration within the cumulative impacts assessment is resource- and project-specific. In general, the effects of past actions are included in the description of the affected environment in Chapter 3, which serves as the baseline for the cumulative impacts analysis. However, past actions that continue to have an overlapping effect on a resource potentially affected by the proposed action are considered in the cumulative analysis.

Other actions and projects identified during this review and considered in the NRC staff's analysis of the potential cumulative effects are described in Appendix E. Not all actions or projects listed in Appendix E are considered in each resource area due to the uniqueness of the resource and its geographic area of consideration.

4.16.1 Air Quality and Noise

This section addresses the direct and indirect effects of license renewal on air quality and noise when added to the aggregate effects of other past, present, and reasonably foreseeable future actions. As described in Section 4.3.1, the incremental impacts on air quality and noise levels from the proposed license renewal would be SMALL.

4.16.1.1 Air Quality

The geographic area considered in the cumulative air quality analysis is the county of the proposed action as air quality designations for criteria air pollutants are generally made at the county level. Counties are further grouped together based on a common airshed—known as an Air Quality Control Region (AQCR)—to provide for the attainment and maintenance of the NAAQS. The Byron site is located in Ogle County, Illinois, which is part of Rockford (Illinois)–Janesville–Beloit (Wisconsin) Interstate AQCR (40 CFR 81.71).

As noted in Section 3.3.2, EPA regulates six criteria pollutants under the NAAQS, including carbon monoxide, lead, nitrogen dioxide, ozone, sulfur dioxide, and PM. With regard to the NAAQS criteria pollutants, Ogle County is designated as an attainment/unclassifiable area for all criteria pollutants (40 CFR 81.314).

Criteria pollutant air emissions from the Byron site are presented in Section 3.3.2; these emissions are from permitted sources including standby emergency diesel generators, auxiliary boilers, AFW pumps, SX makeup water pumps, a fire pump, and two natural draft and two mechanical draft cooling towers (Exelon 2013b). Since there will be no refurbishment-related activities, the NRC staff expects similar emissions during the license renewal period. Therefore, cumulative changes to air quality in Hamilton County and AQCR would be the result of changes to present-day emissions as well as future projects and actions within the county.

Appendix E provides a list of present and reasonably foreseeable projects that could contribute to cumulative impacts to air quality. For example, there are limited industrial facilities, including two landfills, one small hydroelectric power plant, and several water supply and treatment facilities, within the 80-km (50-mi) radius of Byron Station, and IEPA regulates air emissions through air permits. Continued air emissions from existing projects and actions listed in Appendix F as well as proposed new source activities would contribute to air emissions in Ogle County.

At Byron Station, about 60 staff could be added to implement aging management programs and temporary workforces on staggered 18-month refueling cycles (Exelon 2013a). Additionally, Units 1 and 2 reactor pressure vessel head replacement (assumed to occur during a 7-day period with 340 additional workers) and Unit 2 SG replacement (estimated to require an additional 500 workers for 90 days) may occur at Byron. The main contributors to air quality impacts associated with these activities would be fugitive dust generation from construction activities, work to open containment to replace the SGs and related equipment, and exhaust emissions from motorized equipment and vehicles of temporary workers. The additional vehicle air emissions resulting from the additional workforce for SG replacement activities (used as the bounding conditions for this analysis) would be temporary and are estimated to result in an additional 3.3 t (3.0 MT) of VOCs, 9.8 t (8.9 MT) of nitrogen oxides, 0.04 t (0.04 MT) of sulfur dioxide, and 0.40 t (0.36 MT) of $PM_{2.5}$ (direct emissions) being emitted, which do not exceed the de minimis levels of 100 t per year set forth in 40 CFR 93.153(b). Therefore, the additional emissions resulting from these activities at Byron are expected to be minor.

Development and construction activities associated with regional growth of housing, business, and industry, as well as associated vehicular traffic, will also result in additional air emissions. Project timing and location, which are difficult to predict, affect cumulative impacts to air quality. However, permitting and licensing requirements, efficiencies in equipment, cleaner fuels, and various mitigation measures can be used to minimize cumulative air quality impacts. Accordingly, cumulative impacts on air quality are expected to be minor and remain minor during the license renewal term.

Climate change can impact air quality as a result of changes in meteorological conditions. Air pollutant concentrations are sensitive to winds, temperature, humidity, and precipitation (EPA 2009b). As discussed in Section 4.15.3.2, ozone levels have been found to be particularly sensitive to climate change influences (EPA 2009a; Solomon et al. 2007). Sunshine, high temperatures and air stagnation are favorable meteorological conditions leading to higher levels of ozone (EPA 2009a; Solomon et al. 2007). The combination of higher temperatures, stagnant air masses, sunlight, and emissions of precursors may make it difficult to meet ozone NAAQS (Karl et al. 2009). States, however, must continue to comply with the CAA and ensure air quality standards are met.

4.16.1.2 Noise

Section 3.3.3 presents a summary of noise sources at Byron and site vicinity. Noise emission sources from Byron include cooling towers, ventilation supply and exhaust fans, transformers, intake water pumps, transmission lines, infrequent relief valves, onsite vehicle traffic (commuter or delivery trucks), and shooting range activities (Exelon 2013b).

Noise is usually considered as a local problem. Noise levels in the vicinity of a nuclear power plant could increase from planned activities associated with urban, industrial, and commercial development. The magnitude of cumulative impacts depends on the nuclear plant’s proximity to other noise sources. A 3-dBA change in sound level is considered barely discernible, as discussed in Section 3.3.3. A 3-dBA increase would occur with the placement of another identical source over an existing source, (e.g., double the traffic volume). Ongoing or foreseeable future projects in and around the Byron Station as identified in Appendix F would increase noise levels only in the vicinity of their noise sources, and combined noise levels are not expected to be high enough to cause noise issues. For instance, activities at the Byron site related to SG replacement or reactor pressure vessel head replacement, if they occur, would increase noise levels as a result of construction activities related to the storage facility, motorized equipment, and increased vehicles. Construction equipment, for instance, can result in noise levels in the range of 85 to 90 dBA; however, noise levels attenuate rapidly with distance such that at half a mile distance from construction equipment, noise levels can drop to 51 to 61 dBA (NRC 2002). Additional noise from construction activities would be temporary and intermittent and the majority of work activities would occur inside of buildings. The additional noise sources are not expected to be audible beyond the site boundary. Therefore, contributions to noise levels from future actions are limited by projects in the vicinity of Byron. Accordingly, cumulative impacts on noise levels are expected to be minor and remain minor during the license renewal term.

4.16.1.3 Conclusion

Past, present, and reasonably foreseeable future activities exist in the geographic areas of interest (local for noise, local and regional for criteria pollutants) that could affect air quality and noise resources. However, the incremental contribution of impacts on air quality and noise resources from plant operations at Byron Station would be minimal. The NRC staff concludes that cumulative impacts from other past, present, and reasonably foreseeable future actions on air quality and noise resources in the geographic areas of interest would be SMALL.

4.16.2 Geology and Soils

This section addresses the direct and indirect effects of license renewal on geology and soils when added to the aggregate effects of other past, present, and reasonably foreseeable future actions. As noted in Section 2.1.2, Exelon has no plans to conduct refurbishment or replacement actions, and activities associated with continued operations are not expected to affect the geologic environment. Ongoing operation and maintenance activities at the Byron site are expected to be confined to previously disturbed areas, and geologic conditions are not expected to change during the license renewal term. Any use of geologic materials, such as aggregates to support operation and maintenance activities, would be procured from local and regional sources. These materials are abundant in the region, and supplies would be sufficient for any current or future projects in the area requiring these materials. Thus, the NRC staff concludes that the cumulative impact of the proposed license renewal of Byron, when combined with other past, present, and reasonably foreseeable future projects or actions, would be SMALL on geology and soils.

4.16.3 Water Resources

This section addresses the direct and indirect effects of license renewal on surface water and groundwater when added to the aggregate effects of other past, present, and reasonably foreseeable future actions. As described in Sections 4.5.1.1 and 4.5.1.2, the incremental impacts on water resources from continued operations of Byron during the license renewal term would be SMALL. NRC staff also conducted an assessment of other projects and actions for consideration in determining their cumulative impacts on water resources (see Appendix F). The geographic area considered for the surface water resources component of the cumulative impacts analysis spans the Rock River basin. For groundwater, the geographic area of interest is comprised of the local groundwater basin relative to the Byron site, the Ironton-Galesville and Mt. Simon Sandstone aquifers. As such, this review focused on those projects and activities that would (1) withdraw water from or discharge wastewater to the Rock River basin or (2) use groundwater from the Ironton-Galesville and Mt. Simon Sandstone aquifers.

4.16.3.1 Surface Water Resources

The Rock River basin drains an area of approximately 10,915 square miles (mi^2) (17,566 square kilometers (km^2)). Approximately half of the basin is in northern Illinois while the remaining half is in south-central Wisconsin (Section 3.5.1.1, Figure 3–8). From Wisconsin, the river drains southwestward through Illinois and into the Mississippi River. The landscape and soils have a substantial influence on the hydrology of the Rock River basin and the landscape of the Rock

River basin is quite varied. The landscape includes dissected, hilly terrain, rolling hills, and a flat outwash plain. There is also considerable spatial variability in the permeability and drainage characteristics of the soils in the basin. However, land use, another important influence of the hydrology of a drainage basin, is comparatively homogeneous, with more than 85 percent of the basin in row crops or rural grassland (Knapp and Russell 2004).

The total population residing in the Rock River basin in both Wisconsin and Illinois is about 1.7 million people. The two major population centers in the basin are the cities of Rockford, Illinois, and Madison, Wisconsin. Between 1990 and 2000, the population in the Illinois portion of the basin rose by approximately 10 percent as a result of growth near the Chicago metropolitan area. However, the population in the western part of the basin (which includes the Byron site) experienced little or no increases in population. The eastern part of the basin will likely continue to see significant population growth in future decades as the margins of the Chicago metropolitan area continue to expand (Knapp and Russell 2004).

Prior to European settlement, the land cover in the Rock River basin was a mixture of open woodland interspersed with short- and tall-grass prairie. The Rock River basin also had abundant wetlands, lakes, and large marshes. Today, the only remaining large marsh in the watershed is the Horicon Marsh, near the headwaters of the Rock River in northern Dodge County, Wisconsin. It has been designated a “wetland of international importance”. Agriculture (including cultivation, the removal and drainage of wetland areas, stream channelization, and deforestation) has had a large impact on the basin. Most of these major modifications to the landscape occurred in the late 1800s, prior to the onset of stream gaging activities; thus, the large-scale effects of these modifications on stream flow hydrology were not quantitatively measured (IEPA 2006; Knapp and Russell 2004).

There are seven low-head channel dams on the Rock River in Illinois. These dams originally were built in the mid-1800s to early 1900s and are typically 10 to 15 ft (3 to 5 m) high. For the most part, these small reservoirs do not have a noticeable impact on stream flows in the Rock River. From the 1960s through 1999, average stream flow rates for the Rock River in Illinois have increased. These increases appear to be most directly related to increases in the average precipitation over the Rock River basin (IDNR 1998a, 2001).

In Illinois, the Rock River is not used as a source of public water or for navigation (Exelon 2013a). Other than for thermoelectric power generation, most water in the basin used for public, commercial, and industrial purposes is obtained from groundwater (Dziegielewski et al. 2005; IEPA 2006). Much of the water obtained from groundwater is eventually discharged into streams as treated wastewater, which adds additional water to the Rock River.

Surface water from the Rock River in Illinois has been able to support ongoing demands and will likely be sufficient through the license renewal term based on current projections. Future water demand (both groundwater and surface water) in the Illinois counties within the Rock River basin is projected to increase by about 10 percent from 2000 to 2025. Most of this projected demand is for thermoelectric generation near the southern end of the river in the County of Rock Island. The Byron plant is located in Ogle County. In Ogle County, water demand from either surface water or groundwater is projected to increase by only a small amount for all types of water uses (including thermoelectric generation, public supply, commercial, and industrial). From 2005 to 2025, water demand in Ogle County is projected to increase by about 2 percent. This is a 2.1 mgd (7,900 cubic meters per day) increase above 2000 water use (Dziegielewski et al. 2005).

As described in Section 4.15.3.2, future climatic changes are anticipated to result in increased precipitation overall across the region including an increase in heavy-precipitation events, which in turn would tend to result in increased runoff and flow over the headwaters of the Rock River.

If future water demand increases through the period of extended operation (up to 2046) are similar to the projected demand increases between 2005 and 2025, then surface water supplies appear to be abundant enough to meet the reasonably foreseeable demand. Consumptive water use from continued Byron operations will continue to be a very small percentage of the overall flow of the Rock River.

Within Illinois, the surface water quality of the Rock River watershed is judged to be generally good. The primary causes of water quality problems are siltation, suspended solids, hydrologic/habitat modifications, and nutrients largely attributed to agriculture, with some contribution from urban runoff (IEPA 1996). It is reasonable to anticipate that water quality-based limits imposed by NPDES permits on wastewater discharges from Byron and on other industrial facilities will continue to maintain or improve ambient surface water quality in the Rock River.

4.16.3.2 Groundwater Resources

Groundwater resources at the site are described in Section 3.5.2. Byron has not impacted and is not reasonably expected to impact the quality of groundwater in any aquifers that are a current or potential future source of water for offsite users. Byron consumes groundwater from the Ironton-Galesville and Mt. Simon Sandstone aquifers. Because of its depth, the Mt. Simon Sandstone Aquifer is not used as a source of water by local wells. The nearest consumer of Ironton-Galesville and Mt. Simon Sandstone Aquifer groundwater is the City of Byron, which is 6.4 km (4 mi) northwest of the site (Exelon 2013a). Groundwater modeling of the impact of pumping the site groundwater wells at high volumes for an extended period of time did not show any discernible impact on the City of Byron wells (Exelon 2013a).

As discussed in Section 4.15.3, the water demand in Ogle County for all types of water use (including thermoelectric generation, public supply, commercial, and industrial) is projected to increase by only a small amount. Future climatic changes are not anticipated to result in decreased groundwater recharge and the availability of groundwater resources. If future water demand increases through the period of licensing (up to 2046) are similar to the projected demand increases between 2005 and 2025, then groundwater supplies appear to be abundant enough to meet reasonably foreseeable demand.

4.16.3.3 Conclusion

The Byron facility has not impacted and is not expected to impact the quality of groundwater in any aquifers that are a current or potential future source of water for offsite users, and groundwater supply is abundant enough to meet reasonably foreseeable demand. Consumptive surface water use from continued Byron operations will continue to be a very small percentage of the overall flow of the Rock River, and ongoing and future surface water demands by users are expected to be supported. Surface water discharges to the Rock River by Byron and other industrial users will be monitored and kept at acceptable limits via NPDES permits. Considering ongoing activities and reasonably foreseeable actions, the NRC staff concludes that cumulative impact of the proposed license renewal when combined with other past, present, and reasonably foreseeable future activities would be SMALL on surface water and groundwater use and quality.

4.16.4 Terrestrial Resource

This section addresses past, present, and future actions that could result in cumulative impacts on the terrestrial species and habitats described in Section 3.6. For purposes of this analysis, the geographic area considered in the evaluation includes the Byron site. The baseline for this assessment is the condition of the resource without action (i.e., the no-action alternative).

Section 4.6 of this SEIS concludes that the impact from the proposed license renewal would not noticeably alter the terrestrial environment and would be SMALL.

4.16.4.1 Historic Conditions

Section 3.6 discusses the ecoregions in which the Byron site lies, including the central U.S. Plains and the central Corn Belt Plains. Gently rolling smooth plains, irregular plains, and shallow stream valleys characterize much of the area. The native landscape of the ecoregion was composed of bluestem prairie communities and oak–hickory forests, but has mostly been replaced by corn and soybean agriculture. Agricultural lands are the predominant land cover in the ecoregion at 75.3 percent, followed by developed land (11.6 percent), and forests (9.3 percent). Although developed land is less prominent than agricultural land, from 1973 to 2000, the percent of developed land has increased 2.4 percent, while the percent of agricultural land and forested land has decreased (Karstensen et al. 2013).

Approximately 538 ac (218 ha) total of the Byron site was disturbed during the construction of Byron Station (30 percent). Of the Byron site (840 ac (340 ha)), 47 percent has been leased for agricultural use. This land is considered disturbed because most of it is tilled. The remaining 23 percent (404 ac (163 ha)) of Byron is undisturbed land. The terrestrial habitats on the undeveloped portions of the site have not changed significantly since Byron's construction (Exelon 2013b).

4.16.4.2 Urbanization

As the region surrounding the Byron site becomes more developed, habitat fragmentation will increase. Species that require larger ranges, especially predators, will likely suffer reductions in their populations. Herbivores will experience less predation pressure and their populations will likely increase. Edge species will benefit from fragmentation, while species that require interior forest or swamp habitat will likely suffer.

4.16.4.3 Agricultural Runoff

Within Ogle County, 89 percent of land is used for agriculture. The major crops grown in Ogle County are corn and soybeans. Wheat, oats, and hay are also grown (Exelon 2013a). Livestock raised in Ogle County include cattle and hogs (Exelon 2004). The 2000 National Water Quality Inventory reported that agricultural nonpoint source pollution accounted for the second largest source of impairments to wetlands (EPA 2002). Fertilizers and pesticides can affect wetlands and bottomlands in a number of ways. Because wetlands and bottomlands are often at lower elevation than surrounding land, these habitats receive much of the runoff first, and that runoff persists because it is unable to drain to lower ground. This can result in bioaccumulation of pollutants and changes to species composition and abundance. Species that rely on wetlands, such as birds and amphibians, are more sensitive to these environmental stressors than other wildlife.

4.16.4.4 Park and Conservation Areas

In Ogle County, the Lowden-Miller State Forest and the adjacent Castle Rock State Park are both designated Important Bird Areas and contain high-quality terrestrial habitats. Together, this 4,225-ac (1,710-ha) area provides some of the most diverse terrestrial habitats in the Upper Rock River Basin. This State-protected forest will continue to provide valuable habitat to native wildlife and migratory birds during the proposed license renewal period. As habitat fragmentation resulting from various types of nearby development increases, these areas will become ecologically more important because they provide large and diverse areas of natural habitat.

4.16.4.5 Unit 2 Steam Generator Replacement

As discussed in Section 2.1.2, Exelon determined that no major refurbishment or replacement activities were needed to support the operation of Byron beyond the end of the existing operating license (Exelon 2013a). However, in its ER, Exelon (2013a) indicated that it may perform a replacement of Unit 2's SGs during the period of extended operation. Since the Unit 2 SG replacement is not necessary to enter the period of extended operation, the NRC staff is considering this action as a cumulative impact rather than part of the proposed action. Because Exelon has previously replaced the Unit 1 SGs, Exelon would be able to make use of previously built infrastructure if the Unit 2 SGs were to be replaced. An additional SG storage facility or expansion of the existing Unit 1 storage facility could be required, but no undisturbed land would be affected (Exelon 2013a). New SGs would be transported to the site via existing rail and would not require any road or rail upgrades (Exelon 2013a). Wildlife could experience temporary increases in noise and traffic to and from the site during the SG replacement period that could lead to behavioral changes, habitat abandonment, or increased susceptibility to injury or mortality from vehicle strikes. However, because nuclear plants often pair such activities with refueling periods, the incremental increase in noise and traffic attributable to the SG replacement would not create measurable impacts on terrestrial wildlife. Terrestrial habitats and vegetation would be unaffected.

4.16.4.6 Conclusion

Section 4.6 of this SEIS concludes that the impact from the proposed license renewal would not noticeably alter the terrestrial environment and would be SMALL. However, as environmental stressors such as agricultural runoff and residential development continue over the proposed license renewal term, certain attributes of the terrestrial environment (such as species diversity and distribution) are likely to noticeably change. The NRC staff does not expect these impacts to destabilize any important attributes of the terrestrial environment, but instead cause gradual change, which would allow the terrestrial environment to adapt appropriately. The NRC staff concludes that the cumulative impacts of the proposed license renewal of Byron and other past, present, and reasonably foreseeable future projects or actions would result in MODERATE impacts to terrestrial resources.

4.16.5 Aquatic Resources

This section addresses the direct and indirect effects of license renewal on aquatic resources when added to the aggregate effects of other past, present, and reasonably foreseeable future actions. Section 4.7 of this document finds that the direct and indirect impacts on aquatic resources from the proposed license renewal when considered in the absence of the aggregate effects would be SMALL. The cumulative impact is the total effect on the aquatic resources of all actions taken, no matter who has taken the actions (the second principle of cumulative effects analysis in CEQ 1997).

Two related concepts bound the analysis of cumulative impacts: the timeframe and geographic extent. The timeframe for cumulative analyses for ecological resources extends far enough into the past to understand the processes that affect the present resource conditions and to examine whether and why aquatic resources are stable or unstable, which the NRC definitions of impact levels require. The timeframe for cumulative impact analysis is more extensive than that for the direct and indirect impact analysis.

The geographic extent considered in this cumulative aquatic resource analysis depends on the particular cumulative impacts being discussed. Direct and indirect impacts from the Byron site are limited to the Rock River. During preoperational and operational monitoring, studies determined that the effects of Byron operations on aquatic resources are effectively confined to an area of the Rock River that extends from 300 yards (270 m) upstream of the cooling tower blowdown discharge point and continues 0.7 mi (1.1 km) downstream of the discharge point (as discussed in Section 3.7). Fish and other aquatic organisms that occur in this area could travel upstream or downstream. These species' movement would be largely prohibited by dams on the river—the Rockford Dam upstream and the Oregon Dam approximately 5 mi (8 km) downstream of the Byron site—and thus, direct and indirect effects to aquatic resources that could result from continued operation of Byron and other actions could not be meaningfully discerned or described beyond these points. However, projects or actions located beyond this geographic area could directly or indirectly affect the aquatic resources in this area. This section focuses on the cumulative effects of such actions.

The level of cumulative impacts is measured against a baseline. Consistent with the Council on Environmental Quality's (CEQ's) (1997) NEPA guidance, the term "baseline" pertains to the condition of the resource without the action, (i.e., under the no-action alternative). Under the no-action alternative, the plant would shut down and the resource would conceptually return to its condition without the plant (which is not necessarily the same as the condition before the plant was constructed). The baseline, or benchmark, for assessing cumulative impacts on aquatic resources takes into account the preoperational environment as recommended by EPA (1999b) for its review of NEPA documents.

4.16.5.1 Past River Development, Channelization, and Damming

The Rock River basin covers 6,481 mi^2 (10,430 km^2) within Illinois, and Ogle County is wholly contained within the basin. The basin has experienced considerable land use modification since European settlement, which has affected Rock River aquatic resources. Beginning in the early 1900s, several swamps in the Rock River basin were drained, and the river was dredged and channelized for navigation. Seven low-head dams, one of which still operates, were constructed by the 1930s (Sinclair 1996). These changes have divided certain aquatic biota into localized populations and altered stream flow, quality, and aquatic communities significantly.

4.16.5.2 Energy Development

Five nuclear power plant sites with nine operating reactors lie within 50 mi (80 km) of the Byron site (see Appendix E). Because the effects of these facilities would primarily be limited to the water body from which they draw cooling water and none of these facilities draw from the Rock River, the operation of these facilities would not result in cumulative effects to the aquatic resources affected by Byron operation.

The North American Hydro Rockton Plant lies approximately 130 mi (209 km) north of Byron on the Rock River. This facility began operating in 1929, and the Federal Energy Regulatory Commission (FERC) has licensed it to operate through August 2023 (NAH 2014). If this facility's license is renewed, the renewed term would overlap with Byron's proposed license renewal period, which begins in 2024 (Unit 1) and 2026 (Unit 2). Hydroelectric dams are barriers to fish migration, and the transport of fish, eggs, and larvae through the dams result in some mortality (Cada 1991; Watters 2000). Dams alter flow regimes and water quality, which modifies the quality and types of downstream aquatic microhabitats. This facility has likely contributed to significant changes in aquatic communities in the Rock River and will continue to do so during the proposed Byron license renewal period if it is relicensed to operate beyond 2023.

The Nelson Energy Center is a combined-cycle facility that is currently under construction in Rock Falls, Illinois, approximately 26 mi (42 km) southwest of Byron. The facility would begin operating in 2015, prior to the proposed Byron license renewal period, and would use natural gas fuel to operate. The IEPA issued the facility a draft NPDES Permit in August 2013 that would authorize Invenergy Nelson, LLC, to discharge into the Rock River (IEPA 2013). The Nelson Energy Center will be located well downriver of Byron and will be hydrologically separated by the Oregon Dam and the Dixon Dam. Accordingly, the effects of Rock River water use by each facility would not overlap or would be too small to be meaningfully described or detected. Air emissions from the Nelson Energy Center will include GHGs such as nitrogen oxides, carbon dioxide, and methane. Air emissions can have far-reaching consequences because they cumulatively contribute to climate change. The effects of climate change on aquatic resources are discussed in Section 4.15.3.2.

4.16.5.3 Runoff from Agriculture and Municipal Facilities

Illinois river and stream ecosystems historically have had naturally wooded floodplains, which moderated water temperatures and stabilized stream banks to reduce erosion. Less than 10 percent of land bordering the Rock River remains forested, and much of the floodplains have been converted to cropland. This has likely contributed to erosion and sedimentation and will continue to do so during the proposed Byron license renewal period. In 1996, the IEPA rated 67 percent of the Rock River mainstem as "Full Support," which means that these portions of the river meet the needs of all designated uses protected by applicable water quality standards (IDNR 1998b). The IEPA rated the remaining 33 percent of the mainstem as "Partial Support/Minor Impairment," which means that the water quality has been impaired, but only to a minor degree. Suspended solids, phosphorus, and other organic nutrients from agricultural runoff and municipal discharges were major contributors to this rating.

4.16.5.4 Parks and Recreational Areas

Several parks and natural areas lie within the vicinity of Byron (see Appendix E) including Castle Rock State Park, which lies approximately 10 mi (16 km) downstream of the Byron. The continued preservation of these areas will protect aquatic habitats and as land development continues, these areas will become ecologically more important because they will provide large areas of unfragmented natural habitat.

4.16.5.5 Conclusion

NRC staff concludes that the cumulative impacts on aquatic resources in the Rock River are MODERATE based on past, present, and reasonably foreseeable future actions. This level of impact is primarily the result of past river channelization and damming and ongoing runoff and sedimentation from agriculture. The environmental effects of these actions are clearly noticeable, but available information on the status of the Rock River aquatic communities does not indicate that these effects have destabilized any important attribute of the community in the vicinity of Byron. The incremental, site-specific impact from the continued operation of Byron during the license renewal period would be minor and not noticeable in comparison to cumulative impact on the aquatic ecology.

4.16.6 Historic and Cultural Resources

This section addresses the direct and indirect effects of license renewal on historic and cultural resources when added to the aggregate effects of other past, present, and reasonably foreseeable future actions. The geographic area considered in this analysis is the APE associated with the proposed undertaking, as described in Section 3.9.

The archaeological record for the region indicates prehistoric and historic occupation of the Byron site and its immediate vicinity. The construction of Byron resulted in destruction of cultural resources within the Byron site and surrounding area. Other historic land development in the vicinity of Byron also resulted in impacts on, and the loss of, cultural resources on the

Byron site and its immediate vicinity. However, there remains the possibility for additional historic or cultural resources to be located within the Byron site. The present and reasonably foreseeable projects which could affect these resources reviewed in conjunction with license renewal are noted in Appendix F of this document. Direct impacts would occur if historic and cultural resources in the APE were physically removed or disturbed. Indirect visual or noise impact could occur from new construction or maintenance. The following projects are located within the geographic area considered for cumulative impacts:

- Unit 2 SG replacement,
- Units 1 and 2 reactor pressure vessel head replacement, and
- future urbanization in the immediate vicinity of Byron.

As described in Section 4.9, no cultural resources would be adversely affected by Byron Units 1 and 2 license renewal activities as no associated changes or ground-disturbing activities will occur (Exelon 2013a). Unit 2 SG replacement, Units 1 and 2 reactor pressure vessel head replacement, and future urbanization all have the potential to result in impacts on cultural resources through inadvertent discovery during ground-disturbing activities. However, as discussed in Section 4.9, Exelon has established draft procedures to ensure cultural resources are considered in project planning during normal operation of Byron. Therefore, the NRC staff concludes that the cumulative impact of the proposed license renewal on historic and cultural resources, when combined with other past, present, and reasonably foreseeable future activities, would be SMALL.

4.16.7 Socioeconomics

This section addresses socioeconomic factors that have the potential to be directly or indirectly affected by changes in operations at Byron in addition to the aggregate effects of other past, present, and reasonably foreseeable future actions. The primary geographic area of interest considered in this cumulative analysis is Ogle, Lee, and Winnebago counties, where approximately 81 percent of Byron employees reside (see Table 3–16). This is where the economy, tax base, and infrastructure would most likely be affected because Byron workers and their families reside, spend their incomes, and use their benefits within these counties.

As discussed in Section 4.10 of this SEIS, continued operation of Byron during the license renewal term would have no impact on socioeconomic conditions in the region beyond those already being experienced. Since Exelon has no plans to hire additional workers during the license renewal term, overall expenditures and employment levels at Byron would remain relatively constant and unchanged with no additional demand for permanent housing and public services. In addition, as employment levels and tax payments would not change, there would be no population or tax revenue-related land-use impacts. Based on this and other information presented in preceding sections in Chapter 4 of this SEIS, there would be no additional contributory effect on socioeconomic conditions in the future from the continued operation of Byron during the license renewal term beyond what is currently being experienced. Therefore, the only contributory effects would come from reasonably foreseeable future planned activities at Byron, unrelated to the proposed action (license renewal), and other reasonably foreseeable planned offsite activities. For example, residential development is forecast for the Byron area, but not to the point that overall socioeconomic conditions would noticeably change.

4.16.7.1 Unit 2 Steam Generator Replacement

Exelon indicated that the Unit 2 SG replacement would occur during the license renewal term. Exelon estimates that SG replacement would occur during a 90-day period paralleling a refueling outage or other scheduled maintenance outage. Steam generator replacement would require 500 personnel, in addition to the 1,400 personnel required for refueling (Exelon 2013a). These additional workers would create a short-term increase in the demand for temporary (rental) housing, an increased use of public water and sewer services, and transportation impacts on access roads in the immediate vicinity of Byron. Given the short amount of time needed to replace the SG, the additional number of refueling outage and SG replacement workers and truck deliveries needed to support this one-time replacement, SG replacement could have a temporary cumulative effect on socioeconomic conditions in the vicinity of the nuclear plant. However, since the number of nonoutage workers at Byron would not change after SG replacement, there would be no long-term cumulative socioeconomic impacts in the region.

4.16.7.2 Units 1 and 2 Reactor Pressure Vessel Head Replacement

Exelon indicated that the reactor vessel heads would be replaced before the license renewal term. Exelon estimates that each vessel head replacement would require a one-time increase of 340 outage workers for 1 week. If the vessel heads were replaced simultaneously, the number of outage workers would remain at 340, but an additional week of work would be necessary (Exelon 2013a). These additional workers would create a short-term increase in the demand for temporary (rental) housing, an increased use of public water and sewer services, and transportation impacts on access roads in the immediate vicinity of Byron. Given the short amount of time needed to replace the vessel head and the additional number of workers and truck deliveries needed to support this one-time replacement of the vessel head, vessel head replacement could have a temporary cumulative effect on socioeconomic conditions in the vicinity of the nuclear plant. However, since the number of nonoutage workers at Byron would not change after reactor vessel head replacement, there would be no long-term cumulative socioeconomic impacts in the region.

4.16.7.3 Conclusion

When combined with other past, present, and reasonably foreseeable future activities, there will be no additional contributory effect on socioeconomic conditions from the continued operation of Byron during the license renewal period beyond what is currently being experienced. Increases in the Byron workforce during SG and vessel head replacement would be temporary and have no long-term socioeconomic impact to the region. Therefore, the NRC staff concludes that the cumulative socioeconomic impact would be SMALL in the immediate vicinity of Byron.

4.16.8 Human Health

The NRC and EPA established radiological dose limits for protection of the public and workers from both acute and long-term exposure to radiation and radioactive materials. These dose limits are codified in 10 CFR Part 20 and 40 CFR Part 190. As discussed in Section 4.11.1, the NRC staff concluded impacts to human health from continued plant operations are SMALL. For the purposes of this analysis, the geographical area considered is the area included within an 80-km (50-mi) radius of the Byron plant site. There are no other nuclear power plants within the applicable geographical area; however, Byron’s 80-km (50-mi) radius does overlap with the 80-km (50-mi) radii of several nuclear power plants in the area: Quad Cities Nuclear Power Station, Clinton Power Station, Braidwood Station, LaSalle County Station, and Dresden Nuclear Power Station. In addition to storing its spent nuclear fuel in a storage pool, Byron also stores some of its spent nuclear fuel in an onsite independent spent fuel storage installation (ISFSI) (Exelon 2013a).

EPA regulations in 40 CFR Part 190 limit the dose to members of the public from all sources in the nuclear fuel cycle, including nuclear power plants, fuel fabrication facilities, waste disposal facilities, and transportation of fuel and waste. As discussed in Section 3.1.4.5, Byron has conducted a REMP since 1985. This program measures radiation and radioactive materials in the environment from Byron, its ISFSI, and all other sources. The NRC staff reviewed the radiological environmental monitoring results for the 5-year period from 2008 to 2012 as part of the cumulative impacts assessment. The NRC staff's review of Exelon's data showed no indication of an adverse trend in radioactivity levels in the environment from Byron or its ISFSI. The data showed that there was no measurable impact to the environment from the operations at Byron.

In addition, as discussed in Section 2.1.2 of this SEIS, Exelon stated in its ER that the reactor vessel heads for Units 1 and 2 would be replaced before the license renewal term. In addition, Exelon may replace the Byron Unit 2 SGs during the license renewal term. The staff expects the dose to a member of the public and to plant workers from these projects would continue to be a small fraction of the dose limits and standards specified in 10 CFR Part 20, 10 CFR Part 50, Appendix I, and 40 CFR Part 190. The NRC and the State of Illinois will regulate any future development or actions in the vicinity of the Byron site that could contribute to cumulative radiological impacts.

The NRC staff concludes that the cumulative radiological impacts of the proposed license renewal, when combined with other past, present, and reasonably foreseeable future activities, would be SMALL. This is based on the NRC staff's review of REMP data, radioactive effluent release data, Byron's expected continued compliance with Federal radiation protection standards during continued operation and SG replacement, and regulation of any future development or actions in the vicinity of the Byron site by the NRC and the State of Illinois.

4.16.9 Environmental Justice

The environmental justice cumulative impact analysis assesses the potential for disproportionately high and adverse human health and environmental effects on minority and low-income populations that could result from past, present, and reasonably foreseeable future actions, including Byron operations during the renewal term. Adverse health effects are measured in terms of the risk and rate of fatal or nonfatal adverse impacts on human health. Disproportionately high and adverse human health effects occur when the risk or rate of exposure to an environmental hazard for a minority or low-income population is significant and exceeds the risk or exposure rate for the general population or for another appropriate comparison group. Disproportionately high environmental effects refer to impacts or risks of impacts on the natural or physical environment in a minority or low-income community that are significant and appreciably exceed the environmental impact on the larger community. Such effects may include biological, cultural, economic, or social impacts. Some of these potential effects have been identified in resource areas presented in preceding sections of this SEIS. Minority and low-income populations are part of the general public residing in the area and all would be exposed to the same hazards generated from Byron operations. As previously discussed in this chapter, the impact from license renewal for all resource areas (e.g., land, air, water, ecology, and human health) would be SMALL.

As discussed in Section 4.12 of this SEIS, there would be no disproportionately high and adverse impacts on minority and low-income populations from the continued operation of Byron during the license renewal term. Because Exelon has no plans to hire additional workers during the license renewal term, employment levels at Byron would remain relatively constant, and there would be no additional demand for housing or increased traffic. Based on this information and the analysis of human health and environmental impacts presented in the preceding sections, it is not likely there would be any disproportionately high and adverse contributory effect on minority and low-income populations from the continued operation of Byron during the license renewal term. Therefore, the only contributory effects would come from the other reasonably foreseeable future planned activities at Byron, unrelated to the proposed action (license renewal), and other reasonably foreseeable planned offsite activities.

4.16.9.1 Unit 2 Steam Generator Replacement

Potential impacts to minority and low-income populations would mostly consist of environmental and socioeconomic effects (e.g., traffic, employment, and housing impacts). Noise and dust impacts from power plant modifications would be temporary and limited to onsite activities. Minority and low-income populations residing along site access roads could experience increased commuter vehicle traffic during shift changes. Increased demand for inexpensive rental housing during SG-related power plant modifications could disproportionately affect low-income populations; however, due to the short duration of the work and the availability of housing, impacts to minority and low-income populations would be of short duration and limited. Radiation doses from plant operations after power plant modifications are not expected to change and will remain within regulatory limits.

Based on this information and the analysis of human health and environmental impacts presented in this section of the SEIS, Unit 2 SG replacement would not have disproportionately high and adverse human health and environmental effects on minority and low-income populations residing in the vicinity of Byron.

4.16.9.2 Units 1 and 2 Reactor Pressure Vessel Head Replacement

Similar to SG replacement, potential impacts to minority and low-income populations from reactor pressure vessel head replacement would mostly consist of environmental and socioeconomic effects (e.g., traffic, employment, and housing impacts). Noise and dust impacts from power plant modifications would be temporary and limited to onsite activities. Minority and low-income populations residing along site access roads could experience increased commuter vehicle traffic during shift changes. Increased demand for inexpensive rental housing during SG-related power plant modifications could disproportionately affect low-income populations; however, due to the short duration of the work and the availability of housing, impacts to minority and low-income populations would be of short duration and limited. Radiation doses from plant operations after power plant modifications are not expected to change and will remain within regulatory limits.

Based on this information and the analysis of human health and environmental impacts presented in this section of the SEIS, Units 1 and 2 reactor pressure vessel head replacement would not have disproportionately high and adverse human health and environmental effects on minority and low-income populations residing in the vicinity of Byron.

4.16.9.3 Conclusion

The NRC staff concludes that the contributory effects of this action, when combined with other past, present, and reasonably foreseeable future activities considered, would not cause any disproportionately high and adverse human health and environmental effects on minority and low-income populations residing in the vicinity of Byron.

4.16.10 Waste Management and Pollution Prevention

This section describes waste management impacts during the license renewal term when added to the aggregate effects of other past, present, and reasonably foreseeable future actions. For the purpose of this cumulative impacts analysis, the area within a 50-mi (80-km) radius of Byron was considered. The NRC staff concluded, in Section 4.11, that the potential human health impacts from Byron's waste during the license renewal term would be SMALL.

As discussed in Sections 3.1.4 and 3.1.5, Exelon maintains waste management programs for radioactive and nonradioactive waste generated at Byron and is required to comply with Federal and State permits and other regulatory requirements for the management of waste material. Current waste management activities at Byron would likely remain unchanged during the license renewal term, and continued compliance with Federal and State requirements for radioactive and nonradioactive waste is expected.

Byron is adjacent to the Byron Salvage Yard Superfund Site. This salvage yard was used as a dumping ground for a variety of nonradioactive waste and debris. As discussed in Section 3.2.1, all soil and groundwater remedial actions are now completed and groundwater monitoring plans remain in place (EPA 2008).

Based on the above, the NRC staff concludes that the potential cumulative impacts from radioactive and nonradioactive waste during the license renewal term would be SMALL. Continued compliance with Federal and State requirements for radioactive and nonradioactive waste management by Exelon is expected, and the Byron Salvage Yard Superfund Site remediation actions are complete and noncontributory.

4.16.11 Global Climate Change

This section addresses the impact of GHG emissions resulting from continued operation of Byron Station on global climate change when added to the aggregate effects of other past, present, and reasonably foreseeable future actions. The impacts of climate change on air, water, and ecological resources are discussed in Section 4.15.3. Climate is influenced by both natural and human-induced factors; the observed global warming (increase in Earth's surface temperature) in the 21st century has been attributed to the increase in GHG emissions resulting from human activities (Karl et al. 2009). Climate model projections indicate that future climate change is dependent on current and future GHG emissions (Karl et al. 2009; Pachauri and Reisinger 2007). As described in Section 4.15.3.1, operations at Byron Station emit GHG emissions directly and indirectly. Therefore, it is recognized that GHG emissions from continued Byron Station operation may contribute to climate change.

The cumulative impact of a GHG emission source on climate is global. GHG emissions are transported by wind and become well-mixed in the atmosphere as a result of their long atmospheric lifetime. Therefore, the extent and nature of climate change is not specific to where GHGs are emitted. In April 2013, EPA published the official U.S. inventory of GHG emissions, which identifies and quantifies the primary anthropogenic sources and sinks of GHGs. The EPA GHG inventory is an essential tool for addressing climate change and participating with the United Nations Framework Convention on Climate Change to compare the relative global contribution of different emission sources and GHGs to climate change. In 2011, the United States emitted 6,702 teragrams (Tg) of carbon dioxide equivalents (CO_2e) (6,702 million metric tons (MMT)), and since 1990 emissions increased at an average annual rate of 0.4 percent (EPA 2013c). In 2010 and 2011, the total amount of CO_2e emissions related to electricity generation was 2,303 Tg (2,303 MMT) and 2,201 Tg (2,201 MMT), respectively (EPA 2013c). The EIA reported that, in 2010, electricity production alone in Illinois was responsible for 94 MMT CO_2e (EIA 2013). Facilities that emit 25,000 MT (28,000 t) CO_2e or more per year are required to annually report their GHG emissions to EPA. These facilities are known as direct emitters and the data is publicly available in EPA's facility-level information on GHGs tool (FLIGHT). In 2012, FLIGHT identified four facilities in Ogle County, Illinois, where the Byron Station is located, that emitted a total of 0.33 MT (0.36 t) CO_2e (EPA 2013c). In 2012, FLIGHT identified 291 facilities in Illinois that emitted a total of 130.3 MMT (130.3 Tg) CO_2e (EPA 2013c).

Appendix E provides a list of present and reasonable foreseeable projects that could contribute to GHG emissions. Permitting and licensing requirements and other mitigative measures can minimize the impacts of GHG emissions. For instance, in 2012 EPA issued a final GHG Tailoring Rule to address GHG emissions from stationary sources under the CAA permitting requirements; the GHG Tailoring Rule establishes when an emission source will be subject to permitting requirements and control technology to reduce GHG emissions. On June 25, 2013, President Obama set forward a plan to reduce carbon pollution. The Climate Action Plan will reduce carbon pollution, prepare the United States for the impacts of climate change, and lead international efforts to combat global climate change. Future actions and steps taken to reduce GHG emissions will lessen the impacts on climate change.

EPA's U.S. inventory of GHG emissions illustrates the diversity of GHG sources emitters, such as electricity generation, industrial processes, and agriculture. Direct GHG emissions resulting from operations at Byron Station range from 941 to 1,503 MT (1,040 to 1,657 t) CO_2e (Table 4–23) and total emissions range from 10,872 to 13,962 MT (11,984 to 15,390 t) CO_2e. In comparing Byron Station's GHG emission contribution to different emissions sources, whether it be total U.S. GHG emissions, emissions from electricity production in Illinois, or emissions on a county level, GHG emissions from Byron Station are minor relative to these inventories; this is evident as presented in Table 4–23. The emissions impact of a single source on climate change requires that a climate model account for that specific source emission to project the magnitude and extent of climate change. Climate models indicate that short-term climate change (through the year 2030) is dependent on past GHG emissions. Therefore, climate change is projected to occur with or without present and future GHG emissions from Byron Station. The NRC staff concludes that the impact from the contribution of GHG emissions from continued operation of Byron Station on climate change would be SMALL. As discussed in Section 4.15.3.2, climate change and climate-related changes have been observed on a global level and climate models indicate that future climate change will depend on current and future GHG emissions. Climate models project that Earth's average surface temperature will continue to increase and climate-related changes will persist. Therefore, the cumulative impact of GHG emissions on climate change is noticeable but not destabilizing. The NRC staff concludes that the cumulative impacts from the proposed license renewal and other past, present, and reasonably foreseeable projects would be MODERATE.

Table 4–23. Comparison of GHG Emission Inventories

Source	CO_2e MMT/year
Global Fossil Fuel Combustion Emissions (2011)[(1)]	31,800
U.S. Emissions (2011)[(2)]	6,702
Illinois (2012)[(3)]	130.3
Ogle County, Illinois (2012)[(3)]	0.33
Byron Station Emissions (2008–2012)[(4)]	0.010–0.013

[(1)] Source: IEA 2012
[(2)] Source: EPA 2013b
[(3)] GHG emissions account only for direct emitters, those facilities that emit 25,000 MT or more a year (EPA 2013c).
[(4)] Emissions include direct and indirect emissions from operation of Byron (Exelon 2013b).

Sources: EPA 2013b, 2013c; Exelon 2013b; IEA 2012

4.16.12 Summary of Cumulative Impacts

The NRC staff considered the potential impacts resulting from the operation of Byron during the period of extended operation and other past, present, and reasonably foreseeable future actions near Byron. The preliminary determination is that the potential cumulative impacts would range from SMALL to MODERATE, depending on the resource. Table 4–24 summarizes the cumulative impacts on resources areas.

1 **Table 4–24. Summary of Cumulative Impacts on Resource Areas**

Resource Area	Cumulative Impact
Air Quality and Noise	Past, present, and reasonably foreseeable future activities exist in the geographic areas of interest (local for noise; local and regional for criteria pollutants) that could affect air quality and noise resources. However, the incremental contribution of impacts on air quality and noise resources from plant operations at Byron Station would be minimal. The NRC staff concludes that cumulative impacts from other past, present, and reasonably foreseeable future actions on air quality and noise resources in the geographic areas of interest would be SMALL.
Geology and Soils	Any use of geologic materials, such as aggregates to support operation and maintenance activities, would be procured from local and regional sources. These materials are abundant in the region, and geologic conditions are not expected to change during the license renewal term. Thus, activities associated with continued operations are not expected to affect the geologic environment. Considering ongoing activities and reasonably foreseeable actions, the NRC staff concludes that the cumulative impacts on geology and soils during the Byron license renewal term would be SMALL.
Water Resources	Considering ongoing activities and reasonably foreseeable actions, the NRC staff concludes that cumulative impact of the proposed license renewal, combined with other past, present, and reasonably foreseeable future activities, would be SMALL on surface water and groundwater use and quality. The Byron facility has not impacted and is not reasonably expected to impact the quality of groundwater in any aquifers that are a current or potential future source of water for offsite users, and groundwater supply is abundant enough to meet reasonably foreseeable demand. Consumptive surface water use from continued Byron operations will continue to be a very small percentage of the overall flow of the Rock River, and ongoing and future surface water demands by users are expected to be supported. Surface water discharges to the Rock River by Byron and other industrial users will be monitored and kept at acceptable limits via NPDES permits.
Terrestrial Ecology	Section 4.6 of this SEIS concludes that the impact from the proposed license renewal would not noticeably alter the terrestrial environment and would be SMALL. However, as environmental stressors such as agricultural runoff and residential development continue over the proposed license renewal term, certain attributes of the terrestrial environment (such as species diversity and distribution) are likely to noticeably change. The NRC staff does not expect these impacts to destabilize any important attributes of the terrestrial environment, but instead cause gradual change, which would allow the terrestrial environment to adapt appropriately. The NRC staff concludes that the cumulative impacts of the proposed license renewal of Byron, and other past, present, and reasonably foreseeable future projects or actions, would result in MODERATE impacts to terrestrial resources.
Aquatic Ecology	NRC staff concludes that the cumulative impacts on aquatic resources in the Rock River are MODERATE based on past, present, and reasonably foreseeable future actions. This level of impact is primarily the result of past river channelization and damming and ongoing runoff and sedimentation from agriculture. The environmental effects of these actions are clearly noticeable, but available information on the status of the Rock River aquatic communities does not indicate that these effects have destabilized any important attribute of the community in the vicinity of Byron. The incremental, site-specific impact from the continued operation of Byron during the license renewal period would be minor and not noticeable in comparison to cumulative impact on the aquatic ecology.

Resource Area	Cumulative Impact
Historical and Cultural Resources	As described in Section 4.9, no cultural resources would be adversely affected by Byron license renewal activities as no associated changes or ground-disturbing activities will occur. Exelon has established draft procedures to ensure cultural resources are considered in project planning during normal operation of Byron. Therefore, the NRC staff concludes that the cumulative impact of the proposed license renewal when combined with other past, present, and reasonable foreseeable future activities on historic and cultural resources would be SMALL.
Socioeconomics	When combined with other past, present, and reasonably foreseeable future activities, there will be no additional contributory effect on socioeconomic conditions from the continued operation of Byron during the license renewal period beyond what is currently being experienced. Increases in the Byron workforce during SG and vessel head replacement would be temporary and have no long-term socioeconomic impact to the region. Therefore, the NRC staff concludes that the cumulative socioeconomic impact would be SMALL in the immediate vicinity of Byron.
Human Health	The NRC staff concludes that the cumulative radiological impacts of the proposed license renewal, when combined with other past, present, and reasonably foreseeable future activities, would be SMALL.
Environmental Justice	The NRC staff concludes that the contributory effects of this action, when combined with other past, present, and reasonably foreseeable future activities considered, would not cause any disproportionately high and adverse human health and environmental effects on minority and low-income populations residing in the vicinity of Byron.
Waste Management	NRC staff concludes that the potential cumulative impacts from radioactive and nonradioactive waste during the license renewal term would be SMALL. Continued compliance with Federal and State requirements for radioactive and nonradioactive waste management by Exelon is expected, and the Byron Salvage Yard Superfund Site remediation actions are complete and noncontributory.
Global Climate Change	As discussed in Section 4.15.3.2, climate change and climate-related changes have been observed on a global level, and climate models indicate that future climate change will depend on present and future GHG emissions. Climate models project that Earth's average surface temperature will continue to increase and climate-related changes will persist. Therefore, the cumulative impact of GHG emissions on climate change is noticeable but not destabilizing. The NRC staff concludes that the cumulative impacts from the proposed license renewal and other past, present, and reasonably foreseeable projects would be MODERATE.

4.17 Resource Commitments Associated With the Proposed Action

4.17.1 Unavoidable Adverse Environmental Impacts

Unavoidable adverse environmental impacts are impacts that would occur after implementation of all workable mitigation measures. Carrying out any of the energy alternatives considered in this SEIS, including the proposed action, would result in some unavoidable adverse environmental impacts.

Minor unavoidable adverse impacts on air quality would occur due to emission and release of various chemical and radiological constituents from power plant operations. Nonradiological emissions resulting from power plant operations are expected to comply with EPA emissions standards, although the alternative of operating a fossil-fueled power plant in some areas may worsen existing attainment issues. Chemical and radiological emissions would not exceed the National Emission Standards for Hazardous Air Pollutants.

During nuclear power plant operations, workers and members of the public would face unavoidable exposure to radiation and hazardous and toxic chemicals. Workers would be exposed to radiation and chemicals associated with routine plant operations and the handling of nuclear fuel and waste material. Workers would have higher levels of exposure than members of the public, but doses would be administratively controlled and would not exceed standards or administrative control limits. In comparison, the alternatives involving the construction and operation of a nonnuclear power generating facility would also result in unavoidable exposure to hazardous and toxic chemicals to workers and the public.

The generation of spent nuclear fuel and waste material, including low-level radioactive waste, hazardous waste, and nonhazardous waste, would also be unavoidable. In comparison, hazardous and nonhazardous wastes would also be generated at nonnuclear power generating facilities. Wastes generated during plant operations would be collected, stored, and shipped for suitable treatment, recycling, or disposal in accordance with applicable Federal and State regulations. Because of the costs of handling these materials, power plant operators would be expected to carry out all activities and optimize all operations in a way that generates the smallest amount of waste possible.

4.17.2 Relationship Between Short-Term Use of the Environment and Long-Term Productivity

The operation of power generating facilities would result in short-term uses of the environment, as described in this chapter. "Short term" is the period of time that continued power generating activities take place.

Power plant operations require short-term use of the environment and commitment of resources, as well as commitment of certain resources (e.g., land and energy) indefinitely or permanently. Certain short-term resource commitments are substantially greater under most energy alternatives, including license renewal, than under the no-action alternative because of the continued generation of electrical power and the continued use of generating sites and associated infrastructure. During operations, all energy alternatives require similar relationships between local short-term uses of the environment and the maintenance and enhancement of long-term productivity.

Air emissions from power plant operations introduce small amounts of radiological and nonradiological constituents to the region around the plant site. Over time, these emissions would result in increased concentrations and exposure, but they are not expected to impact air quality or radiation exposure to the extent that public health and long-term productivity of the environment would be impaired.

Continued employment, expenditures, and tax revenues generated during power plant operations directly benefit local, regional, and State economies over the short term. Local governments investing project-generated tax revenues into infrastructure and other required services could enhance economic productivity over the long term.

The management and disposal of spent nuclear fuel, low-level radioactive waste, hazardous waste, and nonhazardous waste require an increase in energy and consume space at treatment, storage, or disposal facilities. Regardless of the location, the use of land to meet waste disposal needs would reduce the long-term productivity of the land.

Power plant facilities are committed to electricity production over the short term. After decommissioning these facilities and restoring the area, the land could be available for other future productive uses.

4.17.3 Irreversible and Irretrievable Commitment of Resources

This section describes the irreversible and irretrievable commitment of resources that have been noted in this SEIS. Resources are irreversible when primary or secondary impacts limit the future options for a resource. An irretrievable commitment refers to the use or consumption of resources that are neither renewable nor recoverable for future use. Irreversible and irretrievable commitment of resources for electrical power generation include the commitment of land, water, energy, raw materials, and other natural and manmade resources required for power plant operations. In general, the commitment of capital, energy, labor, and material resources are also irreversible.

The implementation of any of the energy alternatives considered in this SEIS would entail the irreversible and irretrievable commitment of energy, water, chemicals, and in some cases, fossil fuels. These resources would be committed during the license renewal term and over the entire life cycle of the power plant, and they would be unrecoverable.

Energy expended would be in the form of fuel for equipment, vehicles, and power plant operations and electricity for equipment and facility operations. Electricity and fuel would be purchased from offsite commercial sources. Water would be obtained from existing water supply systems. These resources are readily available, and the amounts required are not expected to deplete available supplies or exceed available system capacities.

4.18 References

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5.0 CONCLUSION

This draft supplemental environmental impact statement (SEIS) contains the environmental review of the application for renewed operating licenses for Byron Station, Units 1 and 2 (Byron), submitted by Exelon Generation Company, LLC (Exelon), as required by the *Code of Federal Regulations* (CFR), Part 51 of Title 10 (10 CFR Part 51), the U.S. Nuclear Regulatory Commission's (NRC's) regulations that implement the National Environmental Policy Act (NEPA). This chapter presents conclusions and recommendations from the site-specific environmental review of Byron. Section 5.1 summarizes the environmental impacts of license renewal; Section 5.2 presents a comparison of the environmental impacts of license renewal and energy alternatives; and Section 5.3 presents the NRC staff conclusions and recommendation.

5.1 Environmental Impacts of License Renewal

The NRC staff's review of site-specific environmental issues in this SEIS leads to the conclusion that issuing renewed licenses at Byron would have SMALL impacts for the Category 2 issues applicable to license renewal at Byron. The NRC staff considered mitigation measures for each Category 2 issue, as applicable. The NRC staff concluded that no additional mitigation measure is warranted.

5.2 Comparison of Alternatives

In Chapter 4, the staff considered the following alternatives to Byron license renewal:

- no-action alternative
- new nuclear alternative
- integrated gasification combined cycle (IGCC) alternative
- natural gas combined cycle (NGCC) alternative
- combination alternative (NGCC, wind, solar)
- purchased power

Based on the summary of environmental impacts provided in Table 2-2, the NRC staff concluded that the environmental impacts of renewal of the operating licenses for Byron would be smaller than those of feasible and commercially viable alternatives. The no-action alternative, the act of shutting down Byron on or before its licenses expires, would have SMALL environmental impacts in most areas with the exception of socioeconomic impacts, which would have SMALL to LARGE environmental impacts. Continued operations would have SMALL environmental impacts in all areas. The staff concluded that continued operation of the existing Byron units is the environmentally preferred alternative.

5.3 Recommendations

The NRC staff's preliminary recommendation is that the adverse environmental impacts of license renewal for Byron are not so great that preserving the option of license renewal for energy-planning decisionmakers would be unreasonable. This recommendation is based on the following:

- the analysis and findings in NUREG-1437, Volumes 1 and 2, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*;
- the environmental report submitted by Exelon;
- consultation with Federal, state, and local agencies;
- the NRC staff's environmental review; and
- consideration of public comments received during the scoping process.

6.0 LIST OF PREPARERS

Members of the U.S. Nuclear Regulatory Commission's (NRC's) Office of Nuclear Reactor Regulation (NRR) prepared this supplemental environmental impact statement with assistance from other NRC organizations and support from Argonne National Laboratory (ANL), Pacific Northwest National Laboratory (PNNL), and BLH Technologies, Inc. (BLH). ANL and PNNL provided support as identified in Table 6–1. BLH provided support for technical editing reviews. Table 6–1 identifies each contributor's name, affiliation, and function or expertise.

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(in alphabetical order)

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[b] PNNL is operated by Battelle for the U.S. Department of Energy.

7.0 LIST OF AGENCIES, ORGANIZATIONS, AND PERSONS TO WHOM COPIES OF THIS SEIS ARE SENT

Table 7–1. List of Agencies, Organizations, and Persons to Whom Copies of This SEIS Are Sent

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8.0 INDEX

APPENDIX A
COMMENTS RECEIVED ON THE BYRON STATION ENVIRONMENTAL REVIEW

A. COMMENTS RECEIVED ON THE BYRON STATION ENVIRONMENTAL REVIEW

A.1 Comments Received During the Scoping Period

The scoping process for the environmental review of the license renewal application for Byron Station Units 1 and 2 (Byron) began on August 6, 2013, with the publication of the U.S. Nuclear Regulatory Commission's (NRC's) notice of intent to conduct scoping in the *Federal Register* (78 FR 47800). The scoping process included two public meetings held in Byron, Illinois, on August 20, 2013. Approximately 70 people attended the meetings. After the NRC's prepared statements pertaining to the license renewal process, the meetings were open for public comments. Attendees provided oral statements that were recorded and transcribed by a certified court reporter. A summary and transcripts of the scoping meetings are available using the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS Public Electronic Reading Room is accessible at http://www.nrc.gov/reading-rm/adams.html. The scoping meetings summary can be found under ADAMS Nos. ML13269A006 (package) and ML13240A234 (summary). Transcripts for the afternoon and evening meetings included in the meeting summary package (ML13269A006) can be found under ADAMS Nos. ML13266A183 and ML13266A182, respectively. In addition to comments received during the public meetings, comments were also received electronically and through the mail.

Each commenter was given a unique identifier, so every comment can be traced back to its author. Table A–1 identifies the individuals who provided comments and an accession number to identify the source document of the comments in ADAMS.

Specific comments were categorized and consolidated by topic. Comments with similar specific objectives were combined to capture the common essential issues raised by commenters. Comments have been grouped into the following general categories:

- Specific comments that address environmental issues within the purview of the NRC environmental regulations related to license renewal. These comments address Category 1 (generic) or Category 2 (site-specific) issues identified in NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) or issues not addressed in the GEIS. The comments also address alternatives to license renewal and related Federal actions.

- General comments in support of or opposed to nuclear power or license renewal or comments regarding the renewal process, the NRC's regulations, and the regulatory process.

- Comments that address issues that do not fall within or are specifically excluded from the purview of NRC environmental regulations related to license renewal. These comments typically address issues such as the need for power, emergency preparedness, security, current operational safety issues, and safety issues related to operation during the renewal period.

Table A–1. Individuals Providing Comments During the Scoping Comment Period

Each commenter is identified along with their affiliation and how their comment was submitted.

Commenter	Affiliation (if stated)	ID	Comment Source	ADAMS Number
Chris Millard	City of Byron, Mayor	001	Afternoon Scoping Meeting	ML13269A006
Jared Funderburg	Representative for Congressman Kinzinger, Illinois, 16th District	002 013	Afternoon Scoping Meeting Evening Scoping Meeting	ML13269A006
Russ Kearney	Byron Site VP	003 015	Afternoon Scoping Meeting Evening Scoping Meeting	ML13269A006
Mike Gallagher	Exelon Vice President of License Renewal	004 016	Afternoon Scoping Meeting Evening Scoping Meeting	ML13269A006
Ron Gibson	Byron Township	005	Afternoon Scoping Meeting	ML13269A006
Tom Wolf	Illinois Chamber of Commerce	006	Afternoon Scoping Meeting	ML13269A006
Sarah Fuller	Byron employee	007	Afternoon Scoping Meeting	ML13269A006
Michael Harn	Sheriff of Ogle County	008	Afternoon Scoping Meeting	ML13269A006
Doug O'Brien	Illinois Clean Energy Coalition	009 017	Afternoon Scoping Meeting Evening Scoping Meeting	ML13269A006
Todd Tucker	Executive Director of the Byron Forest Preserve	010	Afternoon Scoping Meeting	ML13269A006
Allen Christianson	Exelon	011	Afternoon Scoping Meeting	ML13269A006
Jenny Beckman	Director of United Way of Ogle County	012	Afternoon Scoping Meeting	ML13269A006
Tom Demmer	State Representative	014	Evening Scoping Meeting	ML13269A006
Ron Colson	Blackhawk Hills Regional Council	018	Evening Scoping Meeting	ML13269A006
Charles Medrano	Byron employee	019	Evening Scoping Meeting	ML13269A006

Commenter	Affiliation (if stated)	ID	Comment Source	ADAMS Number
Dan Westin	Rochelle Utilities	020	Evening Scoping Meeting	ML13269A006
Ronald Bolin	Exelon	021	Evening Scoping Meeting	ML13269A006
Kim Gouker	Ogle County Board	022	Evening Scoping Meeting	ML13269A006
		026	Letter	ML13263A221
Brent Baker	Byron Chamber and Employee of the Byron Bank	023	Evening Scoping Meeting	ML13269A006
Bruce Drawbridge	Vice President with CB&I, Chicago Bridge and Iron	024	Evening Scoping Meeting	ML13269A006
David Kraft	Nuclear Energy Information Service	025	Evening Scoping Meeting	ML13269A006
		027	Letter	ML13277A306
Alan Keller	Illinois Environmental Protection Agency	028	Letter	ML14113A544

Comments that are general or outside the scope of the environmental review for Byron license renewal are not included here but can be found in the Scoping Summary Report (ADAMS No. ML14041A334). To maintain consistency with the Scoping Summary Report, the unique identifier used in that report for each comment is retained in this Appendix A with one exception. One comment was originally placed under Meteorology, Air Quality, and Noise. During the development of the draft SEIS, the comment was addressed better under Climate Change. Comments addressed in this Appendix A are provided at the end of the Scoping Summary Report.

Comments received during the scoping comment period applicable to this environmental review were placed into categories, which are based on topics contained in the Byron draft supplemental environmental impact statement (DSEIS). These categories and their abbreviation codes are listed in Table A–2.

Table A-2 also includes a comment from the Illinois Environmental Protection Agency concerning the renewal of the Byron Station that was received outside of the scoping period.

Table A–2. Issue Categories

Comments were divided into the categories below, each with a unique abbreviation code.

Code	Technical Issue
CC	Climate Change (formerly, Meteorology, Air Quality, and Noise)
AL	Alternatives to License Renewal of Byron
SO	Socioeconomic Impact of Byron
SW	Water Resource – Surface Water

The following pages contain the comments, identified by the commenter's ID, comment number, and comment issue category, and the NRC staff response. Comments are presented in the same order as listed in Table A–2.

A.1.1. Climate Change (CC) (formerly Meteorology, Air Quality, and Noise (ME))

Comment:

027-2 CC - The ER submitted by Exelon is incomplete in not providing evidence that it has examined the projected effects of predicted Illinois climate disruption on future operations. NRC regulations are inadequate for not requiring this examination.

Current climate models suggest that Illinois will gradually assume a climate resembling that of East Texas or Mississippi by mid-Century (within the period of operational life extension of Byron), depending on whether one is running a low- or high- emissions model. Summer temperatures are expected to increase on average from 3.30 to 8.60 F. While total precipitation is expected to remain about the same, seasonal variation will increase, and frequency of heavy precipitation events-measured in terms of number of days per year with more than 2 inches of rain, and annual maximum 24-hr, 5-day and 7-day rainfall totals-is likely to continue to increase, particularly closer to the Great Lakes, a factor which will have implications in the Comments below.

The implications of these projections do not seem to be incorporated into the ER analysis provided by Exelon, which invariably result in the conclusion of "small" impact. The ER clearly states that the Rock River is a "small river" by definition. Make-up water for the mechanical draft cooling tower system relies on the Rock River. Decreased volume and flow rates expected under projected climate disruption models for Illinois could have an adverse effect on the MDCT's ability to function. Since this system is dedicated to cooling the safety-related portions of the plant, this could have serious consequences; but this is not evidenced in the conclusions Exelon arrives at.

Exelon's historic penchant to request license variances on water use and thermal discharge (not a factor at Byron) from IEPA suggests the possibility for greater effect than is characterized in the Exelon ER document. The alternative would be curtailment of operation, which also does not appear factored into the Exelon ER in any manner.

Recommendation: NRC should require a more thorough projection of water use at Byron, based on the best possible climate modeling for Illinois between now and mid-century. Because this variation in climate disruption and its effects are local/regional, it falls outside the scope of a generic analysis or regulation.

Response: *This comment expresses concern over climate change projections and impacts as a result of climate change on operations of Byron. The commenter specifically identifies averaged climate change projections provided in the 2009 U.S. Global Climate Change Research Program report and Hayhoe et al. 2010 for Illinois for the 2040 through 2059 timeframe and 2080 to 2099 timeframe. The NRC has evaluated the potential impacts of climate change upon the affected resources during the Byron license renewal term (2024 through 2044 for Unit 1 and 2026 through 2046 for Unit 2) in Section 4.15.3, "Greenhouse Gas Emissions and Climate Change," of this draft SEIS.*

In informing potential climate change impacts, the NRC staff utilized, among various resources, consensus information from both the 2009 and most recent 2014 U.S. Global Change Research Program report and the National Oceanic and Atmospheric Administration's 2013 climate change report. Section 4.15.3 of the SEIS discusses climate projections for the 2021 through 2050 timeframe, which is appropriate given Byron's license renewal term. Section 4.15.3 *describes the temperature and precipitation trends in the Midwest region, where Byron is located. Specifically, for the license renewal period of Byron and for the State of Illinois, climate model simulations (from 2021 and 2050 relative to the reference period (1971 to 1999)) indicate an increase in annual mean temperature in the Midwest region from 2.5 to 3.5 °F (1.5 to 2.1 °C), an increase in summertime mean temperatures of 3 °F (1.6 °C), and a 0 to 3 percent increase in annual mean precipitation with fall, winter, and spring seasons experiencing precipitation change increases and the summer season experiencing a decrease in precipitation. However, these changes in precipitation were not significant, and the models indicate changes that are less than normal year-to-year variations and projected summertime temperature increases displayed a wide range in temperature ranging in an increase of 1.5 to 5.5 °F (0.76 to 2.98°C) (Kunkel et al. 2013).*

Potential climate change impacts to water resources are discussed in Section 4.15.3.2, the impacts to the Rock River frorm continued operation in Section 4.5.1, and climate change impacts specific to the Rock River in Section 4.16.3.1. However, the impacts of climate change on operations and safety at Byron, as the commenter raises, are addressed as part of the NRC's ongoing reactor oversight process. The NRC evaluates new information that could affect the safety of operating nuclear power plants, such as changes in the operating environment, on an ongoing basis to determine if any changes are needed at existing plants. This ongoing reactor oversight process is separate and distinct from the license renewal process, which is focused on managing the effects of aging on systems, structures, and components during the period of extended operation.

Concerns about the adequacy of NRC regulations may be raised in a petition that asks the NRC to develop, change, or rescind a rule by filing a petition for rulemaking in accordance with the regulations in Title 10 of the Code of Federal Regulations *(10 CFR) 2.802, "Petition for rulemaking." Before filing a petition for rulemaking, a potential rulemaking petitioner may consult with the NRC concerning questions about NRC regulations and rulemaking petition procedures by calling the Rules and Directives Branch at 301-415-7163 or toll-free at 800-368-5642 or by writing to the following address:*

Chief
Rules and Directives Branch
Division of Administrative Services
Office of Administration
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

A.1.2. Socioeconomic Impact of Byron (SO)

Comment:

027-3 SO Analysis of socio-economic impacts are incomplete. No analysis of impacts of early or unexpected closure are considered or provided.

The Exelon ER documents a significant tax impact for the presence of the Byron Nuclear Station, yet only addresses the positive impacts. No mention or analysis of negative impacts resulting from abrupt, planned, or unexpected early closure of Byron is presented. This is a significant omission.

According to the Exelon ER Byron represents nearly 26% of the Ogle County total tax base, roughly $30 million annually for the years 2008 through 2010. It also accounts for upwards of 73% of Byron Unit 226 School District's adjusted property tax levy. These are not insignificant amounts. Their abrupt disappearance would wreak economic havoc on the affected governmental and essential service entities' ability to operate.

- The ER either fails to recognize or mention at all some of the possible events that could result in such a situation:
- Unexpected major accident, resulting in immediate and presumably premature closure
- NRC ordered shut down
- Exelon's unilateral decision to close the plant on economic or other grounds, as it did at Zion, resulting in an immediate loss of about 55% of Zion's tax base
- Devaluation through sale, as occurred at the Clinton station, resulting in enormous loss of tax base
- Eventual old-age, license expiration closure (the outcome most hoped for)

Exelon even provides a possible indication of the kinds of circumstances that would lead it to close Byron on economic grounds. Section 3.2 on Refurbishment indicates that Exelon is well aware that Byron Unit 2 may need a steam generator replacement during the extended operational lifetime. It is also tracking the potential for reactor vessel head replacements at its operating PWRs at both Byron and Braidwood. Should either or both of these conditions emerge at a time of deflated energy prices, or at a time Exelon acknowledges might occur as early as 2024 when renewables are much more cost competitive and approaching base load capabilities (Sec. 7.2, page 7-9), or as the result of multi-season drought curtailing water availability - Exelon being a business will certainly make the calculations it made when it closed Zion, and decide if Byron should continue to operate.

In this omission the ER makes the same mistake the U.S. Government made when it invaded Iraq - it had no exit strategy. To simply assume that the only socio-economic effects of Byron's presence will be positive ones is simply irrational.

Recommendation: Planning for some kind of eventual closure must be made long before it happens to minimize economic and service disruptions to the entities whose tax base will be affected. Debate about the license extension serves as a good reminder of this fact, and an opportunity to take action. We recommend that dependent govemmental and taxing entities begin formal negotiations with Exelon to establish an escrowed "closure mitigation fund," based on some mutually agreeable assessment and payment structure, so that dependent entities will have some kind of temporary funds available to soften the economic blow of closure, and not radically disrupt essential services.

Response: *With the exception of an unexpected major accident and NRC-ordered shutdown for safety reasons, the possible events leading to the closure of Byron identified in this comment involve energy planning decisions that would be made by Exelon and state officials. The NRC has no role in these energy planning decisions. Also, the closure of Byron could occur at any time, including upon the expiration of either the current or renewed operating license.*

Information about Exelon's tax payments is described in Section 3.10.5, "Tax Revenue" in the draft SEIS, and the socioeconomic impacts of station closure and the termination of reactor operations caused by the expiration of the Byron operating license is described as part of the "no action" alternative in the socioeconomic impacts of license renewal section in Chapter 4 in the draft SEIS, specifically Section 4.10.2. The impacts of closing and decommissioning a nuclear power plant are also described in the "Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities: Regarding the Decommissioning of Nuclear Power

Reactors" (NUREG–0586) (NRC 2002). The environmental consequences of decommissioning Byron itself would be during decommissioning.

In regards to what is to be discussed in the ER, 10 CFR 51.45(c) states,

> *Environmental reports prepared at the license renewal stage under § 51.53(c) need not discuss the economic or technical benefits and costs of either the proposed action or alternatives except if these benefits and costs are either essential for a determination regarding the inclusion of an alternative in the range of alternatives considered or relevant to mitigation. In addition, environmental reports prepared under § 51.53(c) need not discuss issues not related to the environmental effects of the proposed action [license renewal] and its alternatives.*

In Section 4.10.2, "No-Action Alternative," under socioecomic impacts, the NRC determined that not renewing the operating licenses and terminating reactor operations could have a noticeable impact on socioeconomic conditions in the communities located near Byron. Specifically, there would be the loss of jobs and income for individuals working at or providing services to Byron, as well as reduced tax revenue in affected tax jurisdictions from the termination of power plant operations. These socioeconomic impacts could range from SMALL to LARGE, depending on the jurisdiction.

A.1.3. Alternatives to License Renewal of Byron (AL)

Comment:

027-5 AL Recommendation: Order Exelon to re-examine its Section 7 comparisons, incorporating: 2.) better data on the capabilities of wind and solar, based on expected improvements in technology, or better and more optimal use decisions…

Response: *Chapter 2 of the draft SEIS describes the alternatives that are discussed further in Chapter 4 and describes the alternatives that were considered but dismissed.*

Specifically, in evaluating alternatives to license renewal, the NRC staff first selects energy technologies or options currently in commercial operation, as well as some technologies not currently in commercial operation but likely to be commercially available by the time the current Byron operating licenses expire in 2024 and 2026.

Second, the NRC staff screens the alternatives to remove those that cannot meet future system needs. Then, the remaining options are screened to remove those alternatives whose costs or benefits do not justify inclusion in the range of reasonable alternatives. Any alternatives remaining, then, constitute alternatives to the proposed action that the NRC staff evaluates in depth throughout Chapter 4.

In Section 2.3.2, solar power was considered as a potential alternative, but dismissed because the NRC staff considers it unlikely that current solar power technologies could serve as baseload power sufficient to replace Byron's output. In Section 2.3.4, wind power was considered as a potential alternative, but dismissed as unreasonable given the amount of wind capacity necessary to replace Byron and the intermittency of wind power. Solar and wind power were considered in combination with a natural gas combined-cycle facility. This combination alternative is described in Section 2.2.2.4 and the impact of this combination alternative is described under each resource area in Chapter 4.

A.1.4. Water Resources - Surface Water (comment not identified in scoping summary report)

Comment:

028-1 SW This Agency received a request on July 5, 2012 from Exelon Generating Company requesting necessary comments concerning the renewal of the Nuclear Regulatory Commission operating licenses for the Byron Generating Stations Units 1 and 2 in Ogle County. We offer the following comments.

This Agency hereby issues certification under Section 401 of the Clean Water Act (PL 95-217), subject to the applicant's compliance with the following conditions:

(1) The applicant shall be responsible for obtaining NPDES permits required for wastewater or stormwater discharges to waters of the State from the proposed activity.

(2) This certification does not cover future activities that require a federal authorization under Section 404 of the Clean Water Act.

This certification becomes effective when the Nuclear Regulatory Commission includes the above conditions # 1 through # 2 as conditions of the requested license issued under the Atomic Energy Act of 1954.

This certification does not grant immunity from any enforcement action found necessary by this Agency to meet its responsibilities in prevention, abatement, and control of water pollution.

Response: *This comment provided input (or data) for the staff's environmental analysis of water resource impacts of Byron on local and regional communities. This comment addresses Clean Water Act (CWA) Section 401 certification of the Byron discharge. The staff discusses water resource impacts, specifically the Section 401 certification in Section 3.5.1 of Chapter 3 of the SEIS.*

On May 12, 2014, Exelon updated its application (Exelon 2014) to inform the staff that by letter to the NRC dated July 5, 2013 (IEPA 2014), the IEPA issued the CWA Section 401 certification for Byron operation during the license renewal.

The NRC understands the importance of the CWA and a delegated State's role in implementing the statute. As early as 1984, the Commission recognized that in revising its regulations, NRC licenses are subject to conditions deemed imposed by the CWA as a matter of law and that the NRC need not duplicate EPA's or a delegated State agency's water quality reviews.[14] *To explicitly recognize that conditions are deemed imposed by the CWA and to remove the need to undertake amendments to incorporate conditions imposed by statute that could be subject to frequent changes by certifying States, the Commission added 10 CFR 50.54(aa)*[15] *to specifically provide that each 10 CFR Part 50 "license shall be subject to all conditions deemed imposed as a matter of law by section 401(a)(2) and 401(d) of the CWA (33 U.S.C.A. 1341(a)(2) and (d)), as amended)." To keep informed of the environmental effects of NRC licensing actions, the Commission relies on reporting requirements of National Pollutant Discharge Elimination System (NPDES) permits to alert the NRC of environmental effects of NRC licensing action. As the Commission stated, "The NRC's role in the water quality area is limited to regulating radiological discharges into aquatic bodies and NEPA matters such as weighing aquatic impacts*

[14] 49 FR. 9352, 9359-60. "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions and Related Conforming Amendments." March 12, 1984.

[15] 49 FR. 9352, 9360.

in NEPA analyses which NRC is required to make before reaching a major Federal licensing decision."[16]

Because the two 401 certification conditions are license requirements either because they are imposed as a matter of law or they state existing statutory provisions, no further NRC action is needed with respect to these two conditions. Specifically, (1) Exelon must obtain a CWA Section 402 (NPDES) permit from the State in accordance with 33 U.S.C. § 1342, and (2) a 401 certification does not authorize activities that require an authorization under Section 404 of the CWA, 33 U.S.C. § 1344 (i.e., the permits for discharges of dredged or fill material, which are issued by the U.S. Army Corps of Engineers). Appendix B, paragraph 3.2 of the current Byron licenses further requires that Exelon provide the NRC copies of any NPDES permit or State certification (or changes to those documents) within 30 days of approval. If the licenses are renewed, this requirement will be carried over to the renewed licenses for Byron Units 1 and 2.

A.2 References

10 CFR Part 51. *Code of Federal Regulations*, Title 10, *Energy*, Part 51, "Environmental protection regulations for domestic licensing and related regulatory functions."

78 FR 47800. U.S. Nuclear Regulatory Commission. "License Renewal Application for Byron Station, Units 1 and 2; Exelon Generation Company, LLC." *Federal Register* 78(151):47800-47802. August 6, 2013.

[Exelon] Exelon Generation Company, LLC. 2013. Byron Station, Units 1 and 2, License Renewal Application, Appendix E, Applicant's Environmental Report, Operating License Renewal Stage. May 29, 2013. Agencywide Documents Access and Management System (ADAMS) Nos. ML13155A422 and ML13155A423.

[Exelon] Exelon Generating Company, LLC. 2014, Update to Chapter 9 of Byron and Braidwood Stations, Units 1 and 2 License Renewal Application, Byron Station Applicant's Environmental Report. May 12, 2014. ADAMS No. ML14132A141.

[IEPA] Illinois Environmental Protection Agency. 2014. Illinois Environmental Protection Agency, Certification under Section 401 of the Clean Water Act (CWA). July 5, 2014. ADAMS No. ML14113A544.

Kunkel KE, Stevens LE, Stevens SE, Sun L (North Carolina State University and National Climatic Data Center), Janssen E, Wuebbles D, Hilberg SD, Timlin MS, Stoecker L, Westcott NE (University of Illinois at Urbana–Champaign), et al. 2013. *Regional Climate Trends and Scenarios for the U.S. National Climate Assessment, Part 3. Climate of the Midwest U.S*. Washington, DC: National Oceanic and Atmospheric Administration (NOAA). NOAA Technical Report NESDIS 142-3. January 2013. 103 p. Available at <http://www.nesdis.noaa.gov/technical_reports/NOAA_NESDIS_Tech_Report_142-3-Climate_of_the_Midwest_U.S.pdf>.

Melillo JM (Marine Biological Laboratory), Richmond TC (Van Ness Feldman, LLP), Yohe GW (Wesleyan University), editors. 2014. *Climate Change Impacts in the United States: The Third National Climate Assessment*. Washington, DC: U.S. Global Change Research Program. May 2014. 841 p. ADAMS No. ML14129A233.

[16] 49 FR. 9352, 9380.

[NRC] U.S. Nuclear Regulatory Commission. 2002. Generic Environmental Impact Statement for Decommissioning of Nuclear Facilities, Supplement 1: Regarding the Decommissioning of Nuclear Power Reactors. NUREG-0586, Supplement 1, Vols. 1 and 2. Office of Nuclear Reactor Regulation, Washington, D.C. November 2002. ADAMS Nos. ML023470327, ML023500228, ML023470304, ML023500295.

[NRC] U.S. Nuclear Regulatory Commission. 2013. Generic Environmental Impact Statement for License Renewal of Nuclear Plants. Washington, DC: NRC. NUREG–1437, Revision 1. June 30, 2013. ADAMS No. ML13107A023.

[NRC] U.S. Nuclear Regulatory Commission. 2014. Summary Of Public Scoping Meetings Conducted Related To The Review Of The Byron Nuclear Station, License Renewal Application (TAC NOS. MF1790 AND MF1791). February 7, 2014. ADAMS No. ML13269A006

APPENDIX B
APPLICABLE LAWS, REGULATIONS, AND OTHER REQUIREMENTS

B. APPLICABLE LAWS, REGULATIONS, AND OTHER REQUIREMENTS

There are a number of Federal laws and regulations that affect environmental protection, health, safety, compliance, and consultation at every nuclear power plant licensed by the U.S. Nuclear Regulatory Commission (NRC). Certain Federal environmental requirements have been delegated to state authorities for enforcement and implementation. Furthermore, states have also enacted laws to protect public health and safety and the environment. It is the NRC's policy to ensure nuclear power plants are operated in a manner that provides adequate protection of public health and safety and protection of the environment through compliance with applicable Federal and state laws, regulations, and other requirements.

The requirements that may be applicable to the operation of NRC-licensed nuclear power plants encompass a broad range of Federal laws and regulations, addressing environmental, historic and cultural, health and safety, transportation, and other concerns. Generally, these laws and regulations are relevant to how the work involved in performing a proposed action would be conducted to protect workers, the public, and environmental resources. Some of these laws and regulations require permits or consultation with other Federal agencies or state, tribal, or local governments.

The Atomic Energy Act of 1954 (as amended) (AEA) (42 United States Code (U.S.C.) § 2011 et seq.) authorizes the U.S. Nuclear Regulatory Commission (NRC) to enter into agreement with any state to assume regulatory authority for certain activities (see 42 U.S.C. § 2021). For example, through the Agreement State Program, Illinois assumed regulatory responsibility over certain byproduct, source, and quantities of special nuclear materials not sufficient to form a critical mass. The Illinois Emergency Management Agency (IEMA), Division of Nuclear Safety administers several programs to protect citizens and the environment, including: a comprehensive monitoring system for the 11 operating nuclear power reactors in Illinois, inspection and regulation of radioactive materials licensees and x-ray machines, and oversight of cleanup efforts at sites contaminated with radioactive materials (IEMA undated).

In addition to carrying out some Federal programs, state legislatures develop their own laws. State statutes supplement, as well as implement, Federal laws for protection of air, water quality, and groundwater. State legislation may address solid waste management programs, locally rare or endangered species, and historic and cultural resources.

The Clean Water Act (33 U.S.C. § 1251 et seq., herein referred to as CWA) allows for primary enforcement and administration through state agencies, given that the state program is at least as stringent as the Federal program. The state program must conform to the CWA and to the delegation of authority for the Federal National Pollutant Discharge Elimination System (NPDES) program from the U.S. Environmental Protection Agency (EPA) to the state. The primary mechanism to control water pollution is the requirement for direct dischargers to obtain an NPDES permit, or, as is the case for Illinois, the authority has been delegated from the EPA, a State Pollutant Discharge Elimination System permit, under the CWA.

One important difference between Federal regulations and certain state regulations is the definition of waters regulated by the state. Certain state regulations may include underground waters, whereas the CWA only regulates surface waters. The Illinois Environmental Protection Agency (IEPA) Bureau of Water, Water Pollution Control conducts the numerous programs, including permit programs and surface water quality monitoring and assessment programs, to protect and enhance the quality of the state's surface waters (IEPA undated).

B.1. Federal and State Requirements

Byron Station, Units 1 and 2 are subject to Federal and State requirements. Table B–1 lists the principal Federal and State regulations and laws that are used or mentioned in this supplemental environmental impact statement (SEIS) for the Byron Nuclear Station.

Table B–1. Federal and State Requirements

Law/regulation	Requirements
Current operating license and license renewal	
Atomic Energy Act (AEA), 42 U.S.C. § 2011 et seq.	The 1954 Atomic Energy Act (AEA), as amended, and the Energy Reorganization Act of 1974 (42 U.S.C. 5801 et seq.) give the NRC the licensing and regulatory authority for nuclear energy uses within the commercial sector. These regulations give the NRC responsibility for licensing and regulating commercial uses of atomic energy and allow the NRC to establish dose and concentration limits for protection of workers and the public for activities under NRC jurisdiction. The NRC implements its responsibilities under the AEA through regulations set forth in Title 10 of the *Code of Federal Regulations* (10 CFR).
National Environmental Policy Act of 1969, as amended (NEPA). 42 U.S.C. 4321, et seq.	The National Environmental Policy Act (NEPA) requires Federal agencies to integrate environmental values into their decisionmaking process by considering the environmental impacts of proposed Federal actions and reasonable alternatives to those actions. NEPA establishes policy, sets goals (in Section 101), and provides means (in Section 102) for carrying out the policy. Section 102(2) contains action-forcing provisions to ensure that Federal agencies follow the letter and spirit of the Act. For major Federal actions significantly affecting the quality of the human environment, Section 102(2)(C) of NEPA requires Federal agencies to prepare a detailed statement that includes the environmental impacts of the proposed action and other specified information.
Title 10 of the *Code of Federal Regulations* (10 CFR), *Energy*, Part 51	Regulations in 10 CFR Part 51, "Environmental protection regulations for domestic licensing and related regulatory functions," contain environmental protection regulations applicable to the NRC's domestic licensing and related regulatory functions.
10 CFR Part 54	Regulations in 10 CFR Part 54, "Requirements for renewal of operating licenses for nuclear power plants," govern the issuance of renewed operating licenses and renewed combined licenses for nuclear power plants licensed pursuant to Sections 103 or 104b of the AEA and Title II of the Energy Reorganization Act of 1974 (88 Stat. 1242). The regulations focus on managing adverse effects of aging. The rule is intended to ensure that important systems, structures, and components will maintain their intended functions during the period of extended operation.
10 CFR Part 50	Regulations in 10 CFR Part 50, "Domestic licensing of production and utilization facilities," are NRC regulations issued under the AEA, as amended (68 Stat. 919), and Title II of the Energy Reorganization Act of 1974 (88 Stat. 1242) to provide for the licensing of production and utilization facilities. This part also gives notice to all persons who knowingly supply—to any licensee, applicant, contractor, or subcontractor—components, equipment, materials, or other goods or services, that relate to a licensee's or applicant's activities subject to this part that they may be individually subject to NRC enforcement action for violation of 10 CFR 50.5.

Law/regulation	Requirements
	Air quality protection
Clean Air Act (CAA), 42 U.S.C. § 7401 et seq.	The Clean Air Act (CAA) is intended to "protect and enhance the quality of the nation's air resources so as to promote the public health and welfare and the productive capacity of its population." The CAA establishes regulations to ensure maintenance of air quality standards and authorizes individual states to manage permits. Section 118 of the CAA requires each Federal agency, with jurisdiction over properties or facilities engaged in any activity that might result in the discharge of air pollutants, to comply with all Federal, state, inter-state, and local requirements with regard to the control and abatement of air pollution. Section 109 of the CAA directs the U.S. Environmental Protection Agency (EPA) to set National Ambient Air Quality Standards (NAAQS) for criteria pollutants. The EPA has identified and set NAAQS for the following criteria pollutants: particulate matter, sulfur dioxide, carbon monoxide, ozone, nitrogen dioxide, and lead. Section 111 of the CAA requires establishment of national performance standards for new or modified stationary sources of atmospheric pollutants. Section 160 of the CAA requires that specific emission increases must be evaluated before permit approval to prevent significant deterioration of air quality. Section 112 requires specific standards for release of hazardous air pollutants (including radionuclides). These standards are implemented through plans developed by each state and approved by the EPA. The CAA requires sources to meet standards and obtain permits to satisfy those standards. Nuclear power plants may be required to comply with the CAA Title V, Sections 501–507, for sources subject to new source performance standards or sources subject to National Emission Standards for Hazardous Air Pollutants. Emissions of air pollutants are regulated by the EPA in 40 CFR Parts 50 to 99.
Illinois Administrative Code (IAC), Title 35, "Environmental Protection," Subtitle B, "Air Pollution," Chapter I, "Pollution Control Board," Subchapter a, "Permits and General Provisions," Part 201, "Permits and General Provisions"	This part of the IAC sets standards for air emissions from auxiliary boilers, emergency generators, radwaste volume reduction system, cooling towers, and ancillary operations.

Law/regulation	Requirements
	Water resources protection
Clean Water Act (CWA), 33 U.S.C. § 1251 et seq., and the NPDES (40 CFR 122)	The CWA was enacted to "restore and maintain the chemical, physical, and biological integrity of the Nation's water." The Act requires all branches of the Federal Government, with jurisdiction over properties or facilities engaged in any activity that might result in a discharge or runoff of pollutants to surface waters, to comply with Federal, state, inter-state, and local requirements. As authorized by the CWA, the National Pollutant Discharge Elimination System (NPDES) permit program controls water pollution by regulating point sources that discharge pollutants into waters of the United States. The NPDES program requires all facilities that discharge pollutants from any point source into waters of the United States to obtain an NPDES permit. A nuclear power plant may also participate in the NPDES General Permit for Industrial Stormwater due to stormwater runoff from industrial or commercial facilities to waters of the United States. EPA is authorized under the CWA to directly implement the NPDES program; however, EPA has authorized many states to implement all or parts of the national program. Section 401 of the CWA requires states to certify that the permitted discharge would comply with all limitations necessary to meet established state water quality standards, treatment standards, or schedule of compliance. The U.S. Army Corps of Engineers is the lead agency for enforcement of CWA wetland requirements (33 CFR Part 320). Under Section 401 of the CWA, the EPA or a delegated state agency has the authority to review and approve, condition, or deny all permits or licenses that might result in a discharge to waters of the State, including wetlands.
Coastal Zone Management Act of 1972, as amended (16 U.S.C. 1451 et seq.)	Congress enacted the *Coastal Zone Management Act* (CZMA) in 1972 to address the increasing pressures of over-development upon the nation's coastal resources. The National Oceanic and Atmospheric Administration administers the Act. The CZMA encourages states to preserve, protect, develop, and, where possible, restore or enhance valuable natural coastal resources such as wetlands, floodplains, estuaries, beaches, dunes, barrier islands, and coral reefs, as well as the fish and wildlife using those habitats. Participation by states is voluntary. To encourage states to participate, the CZMA makes Federal financial assistance available to any coastal state or territory, including those on the Great Lakes, that are willing to develop and implement a comprehensive coastal management program.
IAC, Title 35, "Environmental Protection," Subtitle C, "Water Pollution," Chapter I, "Pollution Control Board," Part 309, "Permits"	This part of the Illinois Administrative Code implements the NPDES program under CWA.
Wild and Scenic Rivers Act, 16 U.S.C. § 1271 et seq.	The Wild and Scenic River Act created the National Wild and Scenic Rivers System, which was established to protect the environmental values of free flowing streams from degradation by impacting activities, including water resources projects.
415 Illinois Compiled Statutes (ILCS) 5, "Environmental Protection Act," Title III, "Water Pollution"	This part of the Illinois Compiled Statutes sets forth state standards for water pollution.

Law/regulation	Requirements
Waste management and pollution prevention	
Resource Conservation and Recovery Act (RCRA), 42 U.S.C. § 6901 et seq.	The Resource Conservation and Recovery Act (RCRA) requires the EPA to define and identify hazardous waste; establish standards for its transportation, treatment, storage, and disposal; and require permits for persons engaged in hazardous waste activities. Section 3006 (42 U.S.C. 6926) allows states to establish and administer these permit programs with EPA approval. EPA regulations implementing the RCRA are found in 40 CFR Parts 260 through 283. Regulations imposed on a generator or on a treatment, storage, and/or disposal facility vary according to the type and quantity of material or waste generated, treated, stored, and/or disposed. The method of treatment, storage, and/or disposal also impacts the extent and complexity of the requirements.
Pollution Prevention Act, 42 U.S.C. § 13101 et seq.	The Pollution Prevention Act establishes a national policy for waste management and pollution control that focuses first on source reduction, then on environmental issues, safe recycling, treatment, and disposal.
10 CFR Part 20,	Regulations in 10 CFR Part 20, "Standards for protection against radiation," establish standards for protection against ionizing radiation resulting from activities conducted under licenses issued by the Nuclear Regulatory Commission. These regulations are issued under the AEA and the Energy Reorganization Act of 1974, as amended. The purpose of these regulations is to control the receipt, possession, use, transfer, and disposal of licensed material by any licensee in such a manner that the total dose to an individual (including doses resulting from licensed and unlicensed radioactive material and from radiation sources other than background radiation) does not exceed the standards for protection against radiation prescribed in the regulations in this part.
IAC Title 35, "Environmental Protection," Subtitle G, "Waste Disposal," Chapter I, "Pollution Control Board," Subchapter c, "Hazardous Waste Operating Requirements," Part 722, "Standards Applicable to Generators of Hazardous Waste"	This part of the IAC establishes standards for generators of hazardous waste.
IAC Title 35, "Environmental Protection," Subtitle C, "Water Pollution," Chapter II, "Environmental Protection Agency," Part 391, "Design Criteria for Sludge Application on Land"	This part of the IAC presents criteria for transporting, storing, and applying sludge on land in an environmentally acceptable manner. In addition, it identifies methods of sludge transportation, handling, storage, application and monitoring to control potential environmental problems.

Law/regulation	Requirements
IAC Title 32, "Energy," Chapter II, "Illinois Emergency Management Agency," Subchapter d, "Low Level Radioactive Waste/Transportation," Part 609, "Access to Facilities for Treatment, Storage, or Disposal of Low-Level Radioactive Waste"	This part of the IAC establishes one of the systems for the regulation of the use of facilities in the State of Illinois to: (1) collect, store, treat or dispose of low-level radioactive waste; (2) maintain a data base as to the location of all such waste in the State of Illinois; and (3) implement some of the requirements, prohibitions and mandates of the Compact, the Radioactive Waste Compact Enforcement Act [45 ILCS 141], the Radioactive Waste Tracking and Permitting Act [420 ILCS 37] and the Illinois Low-Level Radioactive Waste Management Act [420 ILCS 20]. This Part establishes a system for monitoring and tracking shipments of low-level radioactive waste into, out of or within the State of Illinois for the purpose of tracking the points of origin of the shipments, as transported to the places of destination of the shipments. This Part establishes an enforcement and verification system directed to the movements of low-level radioactive waste into, out of or within the State of Illinois. This Part applies to any generator, broker, owner or operator of any treatment or disposal facility, or to any person who sends low-level radioactive waste into, within or out of the State of Illinois.
Protected species	
Endangered Species Act (ESA), 16 U.S.C. § 1531 et seq.	The Endangered Species Act (ESA) was enacted to prevent the further decline of endangered and threatened species and to restore those species and their critical habitats. Section 7 of the Act requires Federal agencies to consult with the U.S. Fish and Wildlife Service or the National Marine Fisheries Service (NMFS) on Federal actions that may affect listed species or designated critical habitats.
Magnuson–Stevens Fishery Conservation and Management Act (MSA), (16 U.S.C. §§ 1801-1884) as amended	The Magnuson-Stevens Fishery Conservation and Management Act (MSA) governs marine fisheries management in U.S. Federal waters. The Act created eight regional fishery management councils and includes measures to rebuild overfished fisheries, protect essential fish habitat, and reduce bycatch. Under Section 305 of the Act, Federal agencies are required to consult with NMFS for any Federal actions that may adversely affect essential fish habitat.
Historic preservation and cultural resources	
National Historic Preservation Act (NHPA), 16 U.S.C. § 470 et seq.	The National Historic Preservation Act (NHPA) was enacted to create a national historic preservation program, including the *National Register of Historic Places* and the Advisory Council on Historic Preservation. Section 106 of the Act requires Federal agencies to take into account the effects of their undertakings on historic properties. The Advisory Council on Historic Preservation regulations implementing Section 106 of the Act are found in 36 CFR Part 800. The regulations call for public involvement in the Section 106 consultation process, including Indian Tribes and other interested members of the public, as applicable.

B.2. Operating Permits and Other Requirements

Table B–2 lists the permits and licenses issued by Federal, state, and local authorities for activities at Byron.

1 **Table B–2. Licenses and Permits**

Permit	Number	Dates	Responsible Agency
Operating license	NPF-37	Issued: 02/14/1985 Expires: 10/31/2024	NRC
Operating license	NPF-66	Issued: 01/30/1987 Expires: 11/06/2026	NRC
National Pollutant Discharge Elimination System (NPDES) Permit	IL0048313	Issued: 01/24/2011 Expires: 12/31/2015	IEPA Division of Water Pollution Control
Water Pollution Control Permit	2011-EP-1250	Issued: 02/16/2011 Expires: 01/31/2016	IEPA Division of Water Pollution Control
Hazardous Materials Certificate of Registration	051713550083VX	Issued: 05/17/2013 Expires: 06/30/2016	U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration
Federally Enforceable State Operating Permit (FESOP)	Application #78090018 9/11/2007; supplemented 12/10/2007 ID# 141820AA	Issued: 12/01/2001 Expires: 12/13/2007[a]	IEPA Division of Air Pollution Control
Notification of Hazardous Waste Activity	ILD000806521	Not Applicable	IEPA Bureau of Land
Land application of sludge	2009-SC-2169-1	Issued: 04/20/2010 Expires: 05/31/2014[b]	IEPA Bureau of Land
Waste tracking permit	IL-0105	Not Applicable	IEMA, Division of Nuclear Safety
License to deliver radioactive material	T-IL007-L12	Renewed annually	Tennessee Department of Environment and Conservation
Permit to deliver radioactive material	0110000032	Renewed annually	Utah Department of Environmental Quality

[a] 415 Illinois Compiled Statutes 5/-, Title X, Permits, Sec. 39(x) establishes the timing for submitting a permit renewal. Specifically, as long as the renewal is submitted before the permit is expired, the current terms and conditions of the permit are extended until the final administrative action has been taken on the application for the renewal of the permit. Because Exelon Generation met this requirement, the permit is administratively extended (415 ILCS 5/39(x)).

[b] The applicant is evaluating future land applications of the river sediment. A permit renewal application will be filed after the evaluation is completed.

Source: Exelon 2014

B.3. References

10 CFR Part 50. *Code of Federal Regulations*, Title 10, *Energy*, Part 50, "Domestic licensing of production and utilization facilities."

10 CFR Part 51. *Code of Federal Regulations*, Title 10, *Energy*, Part 51, "Environmental protection regulations for domestic licensing and related regulatory functions."

10 CFR Part 54. *Code of Federal Regulations*, Title 10, *Energy*, Part 54, "Requirements for renewal of operating licenses for nuclear power plants."

40 CFR Part 122. *Code of Federal Regulations*, Title 40, *Protection of Environment*, Part 122, "EPA administered permit programs: the National Pollutant Discharge Elimination System."

49 CFR Part 107. *Code of Federal Regulations*, Title 49, *Transportation*, Part 107, "Hazardous materials program procedures."

49 U.S.C. 5108. *United States Code*. Title 49, Chapter 51, Part 5108, "Registration."

[IAC] Illinois Administrative Code Title 32, Chapter II, Subchapter d, Part 609, "Access to facilities for treatment, storage, or disposal of low-level radioactive waste."

[IAC] Illinois Administrative Code Title 35, Subtitle B, Chapter I, Subchapter a, Part 201, "Permits and general provisions."

[IAC] Illinois Administrative Code Title 35, Subtitle C, Chapter I, Part 309, "Permits."

[IAC] Illinois Administrative Code Title 35, Subtitle C, Chapter II, Part 391, "Design criteria for sludge application on land."

[IAC] Illinois Administrative Code Title 35, Subtitle G, Chapter I, Subchapter c, Part 722, "Standards applicable to generators of hazardous waste."

[IEMA] Illinois Emergency Protection Agency, Division of Nuclear Safety. Undated. Available at: <http://www.state.il.us/iema/dns.asp> (accessed 14 May 2014).

[IEPA] Illinois Environmental Protection Agency, Bureau of Water. Undated. "Water Pollution Control." Available at: <http://www.epa.state.il.us/water/index-wpc.html> (accessed 14 May 2014).

415 ILCS 5/Tit. II. Illinois Compiled Statutes. Chapter 415, 5, "Environmental Protection Act," Title II, "Air pollution."

415 ILCS 5/Tit. III. Illinois Compiled Statutes. Chapter 415, 5, "Environmental Protection Act," Title III, "Water pollution."

[AEA] Atomic Energy Act of 1954, as amended. 42 U.S.C. § 2011 et seq.

[CAA] Clean Air Act of 1963, as amended. 42 U.S.C. § 7401 et seq.

[CWA] Clean Water Act of 1977, as amended. 33 U.S.C. § 1251 et seq.

[ESA] Endangered Species Act of 1973, as amended. 16 U.S.C. § 1531 et seq.

[Exelon] Exelon Generation Company. LLC. 2014. "Update to Chapter 9 of Byron and Braidwood Stations, Units 1 and 2 License Renewal Application, Byron Station Applicant's Environmental Report." May 12, 2014. Agencywide Documents Access and Management System No. ML14132A141.

[FWCA] Fish and Wildlife Coordination Act of 1934, as amended. 16 U.S.C. § 661 et seq.

[MMPA] Marine Mammal Protection Act of 1972, as amended. 16 U.S.C. § 1361 et seq.

[MSA] Magnuson–Stevens Fishery Conservation and Management Act, as amended. 16 U.S.C. § 1801 et seq.

[NHPA] National Historic Preservation Act of 1966, as amended. 16 U.S.C. § 470 et seq.

Pollution Prevention Act of 1990. 42 U.S.C. § 13101 et seq.

[RCRA] Resource Conservation and Recovery Act of 1976, as amended. 42 U.S.C. § 6901 et seq.

Wild and Scenic Rivers Act, as amended. 16 U.S.C. § 1271 et seq.

APPENDIX C
CONSULTATION CORRESPONDENCE

C. CONSULTATION CORRESPONDENCE

C.1. Section 7 Consultation

C.1.1. Federal Agency Obligations Under ESA Section 7

As a Federal agency, the U.S. Nuclear Regulatory Commission (NRC) must comply with the Endangered Species Act of 1973, as amended (16 *United States Code* (U.S.C.) § 1531 et seq.; herein referred to as ESA), as part of any action authorized, funded, or carried out by the agency, such as the proposed agency action that this supplemental environmental impact statement (SEIS) evaluates: whether to issue renewed licenses for the continued operation of Byron Station, Units 1 and 2 (Byron), for an additional 20 years beyond the current license terms. Under section 7 of the ESA, the NRC must consult with the U.S. Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS) (referred to jointly as “the Services” and individually as “Service”), as appropriate, to ensure that the proposed agency action is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of designated critical habitat.

The ESA and the regulations that implement ESA section 7 (Title 50 of the *Code of Federal Regulations* (50 CFR) Part 402, “Interagency cooperation—Endangered Species Act of 1973, as amended”) describe the consultation process that Federal agencies must follow in support of agency actions. As part of this process, the Federal agency shall either request that the Services provide a list of any listed or proposed species or designated or proposed critical habitats that may be present in the action area or request that the Services concur with a list of species and critical habitats that the Federal agency has created (50 CFR 402.12(c)). If it is determined that any such species or critical habitats may be present, the Federal agency is to prepare a biological assessment to evaluate the potential effects of the action and determine whether the species or critical habitat are likely to be adversely affected by the action (50 CFR 402.12(a); 16 U.S.C. § 1536(c)). Furthermore, biological assessments are required for any agency action that is a “major construction activity” (50 CFR 402.12(b)), which the ESA regulations define to include major Federal actions significantly affecting the quality of the human environment under the National Environmental Policy Act of 1969, as amended (42 U.S.C. § 4321 et seq.; herein referred to as NEPA) (50 CFR 402.02).

Federal agencies may fulfill their obligations to consult with the Services under ESA section 7 and to prepare a biological assessment in conjunction with the interagency cooperation procedures required by other statutes, including NEPA (50 CFR 402.06(a)). In such cases, the Federal agency should include the results of the ESA section 7 consultation in the NEPA document (50 CFR 402.06(b)). Accordingly, Section D.1.2 describes the biological assessment prepared for the proposed agency action evaluated in this SEIS, and Section D.1.3 describes the chronology and results of the ESA section 7 consultation.

C.1.2. Biological Assessment

The NRC considers this SEIS to fulfill its obligation to prepare a biological assessment under ESA section 7. Accordingly, the NRC did not prepare a separate biological assessment for the proposed Byron license renewal.

Although the contents of a biological assessment are at the discretion of the Federal agency (50 CFR 402.12(f)), the ESA regulations suggest information that agencies may consider for inclusion. The NRC has considered this information in the following sections.

Section 3.8 describes the action area and the Federally listed and proposed species and designated and proposed critical habitat that have the potential to be present in the action area. This section includes information pursuant to 50 CFR 402.12(f)(1), (2), and (3).

Section 4.8 provides an assessment of the potential effects of the proposed Byron license renewal on the species and critical habitat present and the NRC's effect determinations, which are consistent with those identified in Section 3.5 of the *Endangered Species Consultation Handbook* (FWS and NMFS 1998). The NRC also addresses cumulative effects and alternatives to the proposed action. This section includes information pursuant to 50 CFR 402.12(f)(4) and (5).

C.1.3. Chronology of ESA Section 7 Consultation

Upon receipt of Exelon's license renewal application, the NRC staff considered whether any Federally listed or proposed species or designated or proposed critical habitats may be present in the action area (as defined at 50 CFR 402.02) for the proposed Byron license renewal. No species under the NMFS's jurisdiction occur within the action area. Therefore, the NRC staff did not consult with the NMFS. With respect to species under the FWS's jurisdiction, the NRC staff compiled a list of ESA-protected species and critical habitats within the vicinity of the facility and requested the FWS's concurrence with this list in accordance with the ESA section 7 regulations at 50 CFR 402.12(c) in a letter dated August 8, 2013. The FWS concurred with the NRC staff's list in an e-mail dated August 30, 2013, and indicated that an additional species—the leafy prairie clover (*Dalea foliosa*)—may potentially be present in the area. The NRC used this correspondence as a starting point for its analysis of effects to Federally listed species, which appears in Sections 3.8 and 4.7 of this SEIS. In Section 3.8, the NRC staff concludes that no ESA-protected species or critical habitats occur in the action area, and Section 4.7 concludes that the proposed action would have no effect on any ESA-protected species or critical habitats. The FWS (2013) does not typically provide its concurrence with "no effect" determinations by Federal agencies. Thus, the ESA does not require further informal consultation or the initiation of formal consultation with the FWS for the proposed Byron license renewal. Nonetheless, because this SEIS constitutes the NRC's biological assessment, the NRC staff will submit a copy of this SEIS, upon its issuance, to the FWS for review in accordance with 50 CFR 402.12(j).

Table C–1 lists the letters, e-mails, and other correspondence related to the NRC's ESA obligations with respect to its review of the Byron license renewal application. This table will be updated in the final SEIS, as applicable, to include correspondence transpiring between the issuance of the draft and final SEIS.

Table C–1. Section 7 Consultation Correspondence

Date	Sender and Recipient	Description	ADAMS Accession No.[(a)]
August 8, 2013	M. Wong (NRC) to T. Melius (FWS)	Request for concurrence with list of Federally listed species and habitats for the proposed Byron license renewal	ML13176A377
August 30, 2013	J. Duyvejonck (FWS) to B. Grange (NRC)	Response to request for concurrence with list of Federally listed species and habitats	ML13246A385
September 3, 2013	B. Grange (NRC) to J. Duyvejonck (FWS)	RE: Response to request for concurrence with list of Federally listed species and habitats	ML13246A386

[(a)] These documents can be accessed through the NRC's Agencywide Documents Access and Management System (ADAMS) at the following URL: http://adams.nrc.gov/wba/.

C.2. Essential Fish Habitat Consultation

The NRC must comply with the Magnuson–Stevens Fishery Conservation and Management Act, as amended (16 U.S.C. § 1801 et seq., herein referred to as MSA), for any actions authorized, funded, or undertaken, or proposed to be authorized, funded, or undertaken that may adversely affect any essential fish habitat (EFH) identified under the MSA.

In Sections 3.8 and 4.8 of this SEIS, the NRC staff concludes that the NMFS has not designated EFH under the MSA in the Rock River and that the proposed Byron license renewal would have no effect on EFH. Thus, the MSA does not require the NRC to consult with the NMFS for the proposed Byron license renewal.

C.3. Section 106 Consultation

The National Historic Preservation Act (NHPA) requires Federal agencies to consider the effects of their undertakings on historic properties and consult with applicable state and Federal agencies, tribal groups, and individuals and organizations with a demonstrated interest in the undertaking before taking action. Historic properties are defined as resources that are eligible for listing on the National Register of Historic Places. The historic preservation review process (16 U.S.C. § 470f) is outlined in regulations issued by the Advisory Council on Historic Preservation (ACHP) in 36 CFR Part 800. In accordance with 36 CFR 800.8(c), the NRC has elected to use the NEPA process to comply with its obligations under Section 106 of the NHPA.

Table C–2 lists the chronology of consultation and consultation documents related to the NRC Section 106 review of the Byron license renewal. The NRC staff is required to consult with the noted agencies and organizations in accordance with the statutes listed above.

1 **Table C–2. NHPA Correspondence**

Date	Sender and Recipient	Description	ADAMS Accession No. [(a)]
August 9, 2013	M. Wong (NRC) to A. Haaker, Illinois Historic Preservation Agency	Request for scoping comments/notification of Section 106 review	ML13190A331
August 9, 2013	M. Wong (NRC) to R. Nelson (ACHP)	Request for scoping comments/notification of Section 106 review	ML13184A052
August 9, 2013	M. Wong (NRC) to J. Greendeer, Ho-Chunk Nation	Request for scoping comments concerning the Byron Nuclear Generating Station, Units 1 and 2, LRA Review (notification of Section 106 review)	ML13184A127
August 9, 2013	M. Wong (NRC) to D. Lankford, Miami Tribe of Oklahoma	Request for scoping comments concerning the Byron Nuclear Generating Station, Units 1 and 2, LRA Review (notification of Section 106 review)	ML13184A127
August 9, 2013	M. Wong (NRC) to J. Froman, Peoria Tribe of Indians of Oklahoma	Request for scoping comments concerning the Byron Nuclear Generating Station, Units 1 and 2, LRA Review (notification of Section 106 review)	ML13184A127
August 9, 2013	M. Wong (NRC) to J. Barrett, Chairman, Citizen Potawatomi Nation	Request for scoping comments concerning the Byron Nuclear Generating Station, Units 1 and 2, LRA Review (notification of Section 106 review)	ML13184A127
August 9, 2013	M. Wong (NRC) to A. Sanache, Chairman, Sac and Fox Tribe of the Mississippi in Iowa/Meskwaki	Request for scoping comments concerning the Byron Nuclear Generating Station, Units 1 and 2, LRA Review (notification of Section 106 review)	ML13184A127
August 9, 2013	M. Wong (NRC) to M. Dougherty, Chairman, Sac and Fox Nation of Missouri in Kansas and Nebraska	Request for scoping comments concerning the Byron Nuclear Generating Station, Units 1 and 2, LRA Review (notification of Section 106 review)	ML13184A127
August 9, 2013	M. Wong (NRC) to G. Thurman, Principal, Sac and Fox Nation	Request for scoping comments concerning the Byron Nuclear Generating Station, Units 1 and 2, LRA Review (notification of Section 106 review)	ML13184A127
August 9, 2013	M. Wong (NRC) to M. Wesaw, Chairman, Pokagon Band of Potawatomi	Request for scoping comments concerning the Byron Nuclear Generating Station, Units 1 and 2, LRA Review (notification of Section 106 review)	ML13184A127

Date	Sender and Recipient	Description	ADAMS Accession No. [(a)]
August 9, 2013	M. Wong (NRC) to H. Frank, Chairman, Forest County Potawatomi	Request for scoping comments concerning the Byron Nuclear Generating Station, Units 1 and 2, LRA Review (notification of Section 106 review)	ML13184A127
August 9, 2013	M. Wong (NRC) to K. Meshigaud, Tribal Chairman, Hannahville Indian Community, Band of Potawatomi	Request for scoping comments concerning the Byron Nuclear Generating Station, Units 1 and 2, LRA Review (notification of Section 106 review)	ML13184A127
August 9, 2013	M. Wong (NRC) to S. Ortiz, Chairman, Prairie Band of Potawatomi Nation	Request for scoping comments concerning the Byron Nuclear Generating Station, Units 1 and 2, LRA Review (notification of Section 106 review)	ML13184A127
August 9, 2013	M. Wong (NRC) to J. Blackhawk, Chairman, Winnebago Tribe of Nebraska	Request for scoping comments concerning the Byron Nuclear Generating Station, Units 1 and 2, LRA Review (notification of Section 106 review)	ML13184A127
August 9, 2013	M. Wong (NRC) to S. Cadue, Chairman, Kickapoo Tribe in Kansas	Request for scoping comments concerning the Byron Nuclear Generating Station, Units 1 and 2, LRA Review (notification of Section 106 review)	ML13184A127
August 9, 2013	M. Wong (NRC) to G. Salazar, Chairman, Kickapoo Tribe of Oklahoma	Request for scoping comments concerning the Byron Nuclear Generating Station, Units 1 and 2, LRA Review (notification of Section 106 review)	ML13184A127
September 4, 2013	A. Haaker, Illinois Historic Preservation Agency to C. Bladey (NRC)	Illinois Historic Preservation Agency Documentation of No Historic Sites Affected by Byron License Renewal Application	ML13269A020

[(a)]These documents can be accessed through the NRC's Agencywide Documents Access and Management System (ADAMS) at http://adams.nrc.gov/wba/.

C.4. References

36 CFR Part 800. *Code of Federal Regulations*, Title 36, *Parks, Forests, and Public Property*, Part 800, "Protection of historic properties."

50 CFR Part 402. *Code of Federal Regulations*, Title 50, *Wildlife and Fisheries*, Part 402, "Interagency cooperation—Endangered Species Act of 1973, as amended."

[ESA] Endangered Species Act of 1973, as amended. 16 U.S.C. § 1531 et seq.

[FWS] U.S. Fish and Wildlife Service. 2013. "Endangered Species Program: What We Do: Consultations: Frequently Asked Questions." July 15, 2013. Available at <http://www.fws.gov/endangered/what-we-do/faq.html#8> (accessed 5 June 2014).

[FWS and NMFS] U.S. Fish and Wildlife Service and National Marine Fisheries Service. 1998. *Endangered Species Consultation Handbook: Procedures for Conducting Consultation and Conference Activities Under Section 7 of the Endangered Species Act*. March 1998. 315 p. Available at <http://www.fws.gov/endangered/esa-library/pdf/esa_section7_handbook.pdf> (accessed 8 July 2013).

[MSA] Magnuson–Stevens Fishery Conservation and Management Act, as amended. 16 U.S.C. § 1801 et seq.

[NEPA] National Environmental Policy Act of 1969, as amended. 42 U.S.C. § 4321 et seq.

[NHPA] National Historic Preservation Act of 1966, as amended. 16 U.S.C. § 470 et seq.

APPENDIX D
CHRONOLOGY OF ENVIRONMENTAL REVIEW CORRESPONDENCE

D. CHRONOLOGY OF ENVIRONMENTAL REVIEW CORRESPONDENCE

This appendix, along with Appendix D, contains a chronological listing of correspondence between the U.S. Nuclear Regulatory Commission (NRC) and external parties as part of its environmental review for Byron Station, Units 1 and 2 (Byron). Appendix D contains the chronological listing of consultation correspondence associated with the Endangered Species Act of 1973 (16 U.S.C. § 1531) and the Magnuson–Stevens Fishery Conservation and Management Act, as amended, (16 U.S.C. § 1801–1884). Appendix C contains all other correspondence.

All documents, with the exception of those containing proprietary information, are available electronically in the NRC's Library, which is found on the Internet at the following Web address: http://www.nrc.gov/reading-rm.html. From this site, the public can gain access to the NRC's Agencywide Documents Access and Management System (ADAMS), which provides text and image files of the NRC's public documents. The ADAMS number for each document is included in the following list. If you need assistance in accessing or searching in ADAMS, contact the Public Document Room Staff at 1-800-397-4209.

D.1. Environmental Review Correspondence

Table D–1 lists the environmental review correspondence in date order beginning with the request by Exelon Generation Company, LLC (Exelon or the applicant), to renew the operating license for Byron.

Table D–1. Environmental Review Correspondence

Date	Correspondence Description	ADAMS No.
29-May-13	License Renewal Application, Byron and Braidwood Stations, Units 1 and 2	ML131620554
31-May-13	Byron License Renewal Application Environmental Report	ML14022A048
06-Jun-13	Receipt and Availability of the License Renewal Application for the Byron Nuclear Station, Units 1 and 2, and the Braidwood Nuclear Station Units 1 and 2	ML13144A099
10-Jun-13	NRC Announces Public Availability of License Renewal Application for Braidwood and Byron Nuclear Power Plants in Illinois	ML13161A381
05-Jul-13	Illinois Environmental Protection Agency, Certification Under Section 401 of the Clean Water Act (CWA)	ML14113A544
16-Jul-13	Determination Of Acceptability And Sufficiency For Docketing, Proposed Review Schedule, And Opportunity For A Hearing Regarding The Application From Exelon Generation Company, LLC, For Renewal Of The Operating Licenses For Byron Nuclear Station, Units 1 and 2, and Braidwood Nuclear Station, Units 1 and 2	ML13134A136
18-Jul-13	*Federal Register* notice (FRN) - License renewal application; notice of docketing and opportunity to request a hearing and to petition for leave to intervene	ML13134A156
24-Jul-13	Press Release-13-062: NRC Announces Hearing Opportunity on License Renewal Application for Byron and Braidwood Nuclear Plants in Illinois	ML13207A291
31-Jul-13	Byron, Notice of Intent to Prepare an Environmental Impact Statement and Conduct Scoping Process, Public Meetings, and Opportunity to Comment	ML13175A072
07-Aug-13	08/20/2013 Forthcoming Meeting to Discuss the License Renewal Process and Environmental Scoping for Exelon Generation Company, LLC (Exelon), Byron Nuclear Station, Units 1 and 2	ML13205A045
08-Aug-13	Notice Of Intent To Prepare An Environmental Impact Statement And Conduct Scoping Process For License Renewal For Byron Station, Units 1 And 2 (TAC Nos. MF1834 And MF1835)	ML13184A110
12-Aug-13	NRC Public Meetings to Discuss Environmental Reviews of Byron, Braidwood Nuclear Plant License Renewals	ML13224A318
27-Aug-13	Comment (2) of Kim P. Gouker on Behalf of Ogle County, Illinois, Supporting License Renewal Application of the Byron Power Generating Station	ML13247A010
04-Sep-13	Illinois Historic Preservation Agency Documentation of No Historic Sites Affected by Byron License Renewal Application	ML13269A020
10-Sep-13	Environmental Site Audit Regarding Byron Station, Units 1 And 2 (TAC Nos. MF1834 and MF1835)	ML13231A060

Date	Correspondence Description	ADAMS No.
16-Sep-13	Comment (1) of Kim P. Gouker on Behalf of Ogle County, Illinois, Supporting the License Renewal Application of the Byron Power Generating Station	ML13263A221
23-Sep-13	Hearing Request and Petition to Intervene by the Environmental Law and Policy Center	ML13270A137
27-Sep-13	Comment (2) of David Kraft on Behalf of NEIS re Supplement to NRC's Generic Environmental Impact Statement for License Renewal for the Byron Nuclear Power Station	ML13277A306
04-Oct-13	Summary of the Site Audit Related to the Review of the License Renewal Application for Byron Nuclear Station, Units 1 and 2 (TAC Nos. MF1834 and MF1835)	ML13270A069
04-Oct-13	Summary of Public Scoping Meetings Conducted Related to the Review of the Byron Nuclear Station, License Renewal Application (TAC Nos. MF1790 and MF1791)	ML13240A234
04-Oct-13	Memorandum from Andrew L. Bates, Acting Secretary of the Commission, to E. Roy Hawkens, Chief Administrative Judge of the Atomic Safety and Licensing Board, Referring the hearing request and petition to intervene from the Environmental Law and Policy Center	ML13277A454
08-Oct-13	Establishment of Atomic Safety and Licensing Board	ML13281A798
28-Oct-13	NRC Staff Answer to Environmental Law and Policy Center Hearing Request and Petition to Intervene	ML13301A922
28-Oct-13	Exelon's Answer Opposing the Hearing Request and Petition to Intervene Filed by the Environmental Law and Policy Center	ML13301A773
29-Oct-13	License Renewal Environmental Site Audit re Byron and Braidwood Stations - Severe Accident Mitigation Alternative (TAC Nos. MF1834/1835, MF1790/1791, MF1832/1833, and MF1792/1793)	ML13270A116
04-Nov-13	Reply in Support of the Environmental Law and Policy Center's Hearing Request and Petition to Intervene	ML13308D017
19-Nov-13	Memorandum and Order (Denying Hearing Request and Petition to Intervene)	ML13323A823
21-Nov-13	Requests For Additional Information For The Environmental Review Of The Byron Nuclear Station, Units 1 And 2, License Renewal Application	ML13294A341
13-Dec-13	Audit Trip Report SAMA	ML13312A317
19-Dec-13	Byron, Units 1 and 2, Response to NRC Request for Additional Information, dated November 21, 2013, Related to the Byron and Braidwood, Units 1 and 2, License Renewal Application, Byron Station Applicant's Environmental Report	ML14007A078
02-Jan-14	ELPC Reply in Support of Its Appeal of the ASLB Denial of ELPC's Petition for Intervention and Hearing Request	ML14002A455

Date	Correspondence Description	ADAMS No.
06-Jan-14	Requests for Additional Information for the Review of the Byron and Braidwood Nuclear Stations License Renewal Application - Severe Accident Mitigation Alternatives Review (TAC Nos. MF1790, MF1791, MF1792, and MF1793)	ML13318A208
13-Jan-14	Byron Environmental RAIs - 1 supplemental request	ML14013A339
23-Jan-14	Byron-Braidwood SAMA RAI Conference Call Summary	ML14007A240
23-Jan-14	ELPC's Motion for Leave to File Its Reply	ML14023A884
29-Jan-14	Requests For Additional Information For The Environmental Review Of The Byron Nuclear Station, Units 1 And 2, License Renewal Application - Additional Request	ML14014A036
03-Feb-14	Exelon's Answer Opposing ELPC's Untimely Motion for Leave to File a Reply	ML14034A313
03-Feb-14	NRC Staff Answer Opposing Environmental Law and Policy Center Motion for Leave to File Reply	ML14034A406
04-Feb-14	Braidwood, Units 1 & 2, and Byron, Units 1 & 2, Response to NRC Requests for Additional Information for the Severe Accident Mitigation Alternatives Review, dated January 6, 2014, License Renewal Application	ML14035A512
11-Feb-14	Byron Station, Units 1 & 2, Response to NRC Request for Additional Information on License Renewal Application and Environmental Report	ML14045A101
05-May-14	Schedule Revision for Environmental Review of Byron and Braidwood Nuclear Stations License Renewal Application - Environmental Review Schedule (TAC Nos. MF1790, MF1791, MF1792, And MF1793).	ML14104B131
07-May-14	Commission Decision (CLI-14-06) Denying the Request for a Protective Stay of the Byron/Braidwood License Renewal Proceeding.	ML14127A220
12-May-14	Update to Chapter 9 of Byron and Braidwood Stations, Units 1 and 2 License Renewal Application, Byron Station Applicant's Environmental Report.	ML14132A141
28-May-14	Issuance Of Environmental Scoping Summary Report Associated With The Staff's Review Of The Byron Nuclear Station, Units 1 And 2, License Renewal Application.	ML14041A334
17-Oct-14	Schedule Revision for the Environmental Review of the Byron Station And Braidwood Station License Renewal Application—Environmental Review Schedule (TAC Nos. MF1790, MF1791, MF1792, And MF1793).	ML14275A003

APPENDIX E
PROJECTS CONSIDERED IN THE CUMULATIVE IMPACTS ANALYSIS

E. PROJECTS CONSIDERED IN THE CUMULATIVE IMPACTS ANALYSIS

Table E–1 identifies actions and projects considered in the U.S. Nuclear Regulatory Commission (NRC) staff's analysis of cumulative impacts related to the environmental analysis of the continued operation of Byron Station, Units 1 and 2 (Byron). Potential cumulative impacts associated with these actions and projects are addressed in Section 4.16 of this SEIS. However, not all actions or projects listed in this appendix are considered in each resource area because of the uniqueness of the resource and its geographic area of consideration.

1 **Table E–1. Projects and Actions Considered in the Cumulative Impacts Analysis**

Project Name	Summary of Project	Location (relative to Byron)	Status
Nuclear projects			
Quad Cities Nuclear Power Station, Units 1 and 2	Nuclear power plant, two 867-MWe General Electric Type 3 reactors	Rock Island County, IL, 50 mi (~80 km) radius overlaps with Byron	Operational (NRC 2014a, 2014b)
Clinton Power Station, Unit 1	Nuclear power plant, one 1,043-MWe General Electric Type 6 reactor	DeWitt County, IL, 50 mi (~80 km) radius overlaps with Byron	Operational (NRC 2014c)
Braidwood Station, Units 1 and 2	Nuclear power plant, two 1,121-MWe Westinghouse four-loop reactors	Will County, IL, 50 mi (~80 km) radius overlaps with Byron	Operational (NRC 2014d, 2014e)
LaSalle County Station, Units 1 and 2	Nuclear power plant, two 1,200-MWe General Electric Type 5 reactors	LaSalle County, IL, 50 mi (~80 km) radius overlaps with Byron	Operational (NRC 2014f, 2014g)
Dresden Nuclear Power Station, Units 2 and 3	Nuclear power plant, two 867-MWe General Electric Type 3 reactors	Grundy County, IL, 50 mi (~80 km) radius overlaps with Byron	Operational (NRC 2014h, 2014i)
Dresden Nuclear Power Station, Unit 1	Nuclear power plant	Grundy County, IL, 50 mi (~80 km) radius overlaps with Byron	Shut down in October 1978 and is currently in SAFSTOR. No dismantlement activities are underway. All spent fuel from DNPS Unit 1 transferred to the onsite Independent Spent Fuel Storage Installation (NRC 2014j).
Hydroelectric project			
North American Hydro Rockton Plant	Hydroelectric power plant located on the Rock River; two units totaling 1,100 kW installed generating capacity	Rockton, IL, approximately 28 mi (~45 km) north	Operational (NAH 2014)
Gas fired project			
Nelson Energy Center	Combined-cycle plant with 584 MWe generating capacity	Rock Falls, IL, approximately 29 mi (~47 km) south	Under construction; projected to open 2015 (Invenergy 2014)

Project Name	Summary of Project	Location (relative to Byron)	Status
Landfills			
Rochelle Municipal Landfill No. 2	Permitted landfill area of 80.6 ac (32.6 ha) and a permitted disposal area of 61.3 ac (24.8 ha); design capacity of 14,516,000 yd^3 (11,098,000 m^3)	Creston, IL, approximately 19 mi (~31 km) southeast	Operational, NPDES Permit No. IL0075451 (IEPA 2013)
Veolia ES Orchard Hills Landfill	Permitted landfill area of 446.32 ac (180.62 ha) and a permitted disposal area of 251.1 ac (101.6 ha); design capacity of 45,369,400 yd^3 (34,687,300 m^3)	Davis Junction, IL, approximately 9 mi (~15 km) east	Operational, NPDES Permit No. IL0075591 (IEPA 2013)
Water supply and treatment facilities			
City of Byron, water supply	Withdraws groundwater from Galesville and St. Simon aquifers	Byron, IL, approximately 3 mi (~5 km) northeast	Operational (EPA 2014c)
City of Byron, wastewater plant	Sewage treatment facility on the Rock River	Byron, IL, approximately 3 mi (~5 km) northeast	Operational, NPDES Permit No. IL0027804 (EPA 2014a)
City of Oregon, water supply	Withdraws groundwater	Oregon, IL, approximately 5 mi (~8 km) northeast	Operational (EPA 2014b)
Rock River Water Reclamation District	Water treatment plant with discharge to Rock River	Rockford, IL, approximately 16 mi (~26 km) northeast	Operational, NPDES Permit No. IL0027201 (EPA 2014a)
City of Oregon, municipal wastewater treatment facilities	Sewage treatment facility on the Rock River	Oregon, IL, approximately 5 mi (~8 km) northeast	Operational, NPDES Permit No. IL0020184 (EPA 2014a)
Various minor NPDES wastewater discharges	Various businesses with smaller wastewater dischargers to water bodies	Within 50 mi (~80 km)	Operational (EPA 2014a)

Project Name	Summary of Project	Location (relative to Byron)	Status
Transportation			
Jane Addams Memorial Tollway (I-90)	Major projects include completion of a new interchange at Illinois Route 47. Rebuilding and widening of the eastbound lanes between Rockford and Elgin, including work on mainline bridges and nine local crossroad bridges and ramp reconstruction at the Business U.S. Route 20/State Street Interchange in Rockford	Within 35 mi (~56 km)	In progress by Illinois Department of Transportation; expected to finish in 2016 (Illinois Tollway 2014)
Parks and recreation sites			
Franklin Creek State Natural Area	356 ha (~880 ac) near Franklin Grove, IL, with natural springs, hardwood forests, bedrock outcroppings, and a large variety of flora and fauna for various recreational activities	Approximately 15 mi (~24 km) south	Operational; managed by Illinois Department of Natural Resources (IDNR 2014a)
Castle Rock State Park	809 ha (~2,000 ac) on the west bank of the Rock River in Ogle County; hiking, fishing, camping, and small-game hunting occur within the park	Approximately 9 mi (~14 km) southwest	Operational; managed by Illinois Department of Natural Resources (IDNR 2014b)
Lowden State Park	95 ha (~235 ac) along the Rock River in Ogle County; hiking, fishing, and camping occur within the park	Approximately 4 mi (~6 km) southwest	Operational; managed by Illinois Department of Natural Resources (IDNR 2014c)
White Pines Forest State Park	155 ha (~383 ac) in the Rock River Valley; hiking, fishing, and camping occur within the park	Approximately 11 mi (~18 km) west	Operational; managed by Illinois Department of Natural Resources (IDNR 2014d)
Recreational Areas	Various parks, boat launches, campgrounds, and swimming areas on the Rock River	Within 50 mi (~80 km)	Operational

Project Name	Summary of Project	Location (relative to Byron)	Status
Byron projects			
Unit 2 steam generator replacement	Assumed to occur during normal refueling outage; 500 additional workers specific to replacement; all work to occur on previously disturbed land on site	Byron site	Assumed to occur prior to the end of the 40-year initial license term (Exelon 2013)
Units 1 and 2 reactor pressure vessel head replacement	Would occur during a 7-day period; 340 additional workers specific to replacement; all work and storage of reactor pressure vessel heads to occur on previously disturbed land	Byron site	Assumed to occur during license term (Exelon 2013)
Other projects			
Future Urbanization	Construction of housing units and associated commercial buildings; roads, bridges, and rail; water or wastewater treatment or both; and distribution facilities and associated pipelines as described in local land-use planning documents	Throughout region	Construction would occur in the future as described in State and local land-use planning documents

Sources: EPA 2014a, 2014b, 2014c; Exelon 2013; IDNR 2014a, 2014b, 2014c, 2014d; IEPA 2013; Illinois Tollway 2014; Invenergy 2014; NAH 2014; NRC 2014a, 2014b, 2014c, 2014d, 2014e, 2014f, 2014g, 2014h, 2014i, 2014j

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APPENDIX F

U.S. NUCLEAR REGULATORY COMMISSION STAFF EVALUATION OF SEVERE ACCIDENT MITIGATION ALTERNATIVES FOR BYRON STATION, UNITS 1 AND 2, IN SUPPORT OF LICENSE RENEWAL APPLICATION REVIEW

F. U.S. NUCLEAR REGULATORY COMMISSION STAFF EVALUATION OF SEVERE ACCIDENT MITIGATION ALTERNATIVES FOR BYRON STATION, UNITS 1 AND 2, IN SUPPORT OF LICENSE RENEWAL APPLICATION REVIEW

F.1 Introduction

Exelon Generation Company, LLC (Exelon) submitted an assessment of severe accident mitigation alternatives (SAMAs) for the Byron Station, Units 1 and 2 (Byron), as part of the Environmental Report (ER) (Exelon 2013b). This assessment is based on the most recent Byron probabilistic risk assessment (PRA) available at that time, a plant-specific offsite consequence analysis performed using the MELCOR Accident Consequence Code System 2 (MACCS2) computer code, and insights from the Byron individual plant examination (IPE) (ComEd 1994) and individual plant examination of external events (IPEEE) (ComEd 1996). In identifying and evaluating potential SAMAs, Exelon considered SAMAs that addressed the major contributors to core damage frequency (CDF) and release frequency at Byron, as well as potential SAMA candidates at other operating plants that have submitted license renewal applications. Exelon initially identified 30 potential SAMAs. This list was reduced to 27 unique SAMA candidates by eliminating SAMAs that were not applicable to Byron because of design differences, that have already been implemented at Byron or the intent achieved by other means, or that have excessive implementation costs. One additional candidate SAMA was also further evaluated after accounting for analysis uncertainties. Exelon assessed the costs and benefits associated with each of the 28 potential SAMAs and concluded in the ER that 18 of the candidate SAMAs evaluated are potentially cost-beneficial. Exelon submitted all 18 potentially cost-beneficial SAMAs to the Byron Plant Health Committee for further implementation consideration.

Based on a review of the SAMA assessment and plant audit trip conducted November 4, 5, and 6, 2013, the U.S. Nuclear Regulatory Commission (NRC) staff issued requests for additional information (RAIs) to Exelon by letter dated January 6, 2014 (NRC 2014). Key questions concerned the disposition of internal and external review comments on the PRA model, the modeling of systems shared between units, additional details on the Level 2 and 3 PRA models, the scope and status of the Byron fire PRA model, the estimated seismic CDF, the identification of candidate SAMAs, the basis for the SAMA cost estimates, and the results of the uncertainty analysis. Exelon submitted additional information by letter dated February 4, 2014 (Exelon 2014). In the responses, Exelon provided a discussion of the conduct of the PRA model self-assessment and the resolution of review findings, a discussion of the modeling of shared systems and the incorporation of opposite unit equipment unavailabilities, clarification of Level 2 and 3 PRA modeling details and assumptions, further details on the Byron fire PRA, analyses of additional SAMAs, updated SAMA cost information, and revised SAMA benefit analyses to fully account for seismic events and uncertainty. Exelon's responses addressed the NRC staff's comments and resulted in the identification of additional potentially cost-beneficial SAMAs.

As a result of NRC staff RAIs, Exelon identified two additional cost-beneficial SAMAs. Exelon plans to implement one of these SAMAs and initiated engineering and procurement activities to do so. However, Exelon determined that the other SAMA would not be cost-beneficial if another SAMA that addresses insights from the Fukushima Dai-ichi accident were implemented since it would mitigate many of the largest contributors to Byron risk.

An assessment of SAMAs for Byron is presented below.

F.2 Estimate of Risk for Byron

Exelon's estimates of offsite risk at Byron are summarized in Section F.2.1. The summary is followed by the NRC staff's review of Exelon's risk estimates in Section F.2.2.

F.2.1 Exelon's Risk Estimates

Exelon combined two distinct analyses to form the basis for the risk estimates used in the SAMA analysis: (1) the Byron Level 1 and 2 PRA models, both new models developed since the IPE models, and (2) a supplemental analysis of offsite consequences and economic impacts (a Level 3 PRA model) developed specifically for the SAMA analysis. The SAMA analysis is based on the most recent Byron Level 1 and Level 2 PRA model available at the time of the ER, the Byron PRA (Revision BB011b1). The scope of this Byron PRA includes internal floods but does not include external events.

The Byron CDF is approximately 4.0×10^{-5} per year for Unit 1 and 3.8×10^{-5} per year for Unit 2 (Exelon 2013b). Exelon did not explicitly include the contribution from external events within the Byron SAMA risk estimates; however, it did account for the potential risk reduction benefits associated with external events by multiplying the estimated benefits for internal events by 2.5. This is discussed further in Sections F.2.2 and F.6.2.

The breakdown of CDF by initiating event is provided in Table F–1. As shown in this table, events initiated by loss of essential service water (SX), loss of component cooling water (CCW), and internal flooding are the dominant contributors to the CDF for both units. Exelon identified that station blackout (SBO) contributes 9.9×10^{-7} per year, or 2.5 percent, for Unit 1, and 9.6×10^{-7} per year, or 2.6 percent, for Unit 2, to the total internal events CDF while anticipated transients without scram (ATWS) contribute 1.4×10^{-7} per year, or approximately 0.4 percent, of the total CDF for each unit (Exelon 2014).

Table F–1. Byron CDF for Internal Events

Initiating Event	Unit 1 CDF (per year)	Unit 1 Percent CDF Contribution	Unit 2 CDF (per year)	Unit 2 Percent CDF Contribution
Loss of Essential Service Water (SX)	1.8×10^{-5}	46	1.7×10^{-5}	45
Loss of Component Cooling Water (CCW)	8.3×10^{-6}	21	8.1×10^{-6}	21
Internal Flooding	5.6×10^{-6}	14	5.8×10^{-6}	15
Loss of Auxiliary Power (AP)	2.4×10^{-6}	6	1.8×10^{-6}	5
Small Loss-of-Coolant Accident (LOCA)	1.6×10^{-6}	4	1.5×10^{-6}	4
Other Initiating Events	1.6×10^{-6}	4	1.6×10^{-6}	4
Steam Generator Tube Rupture (SGTR)	1.2×10^{-6}	3	1.5×10^{-6}	4
General Transient and Loss of Main Feedwater (LMFW)	7.9×10^{-7}	2	6.8×10^{-7}	2
Total (Internal Events) [(a)]	$\mathbf{4.0\times10^{-5}}$	**100**	$\mathbf{3.8\times10^{-5}}$	**100**

[(a)] Column totals may be different because of rounding.

Source: Exelon 2013b

The Level 2 Byron PRA model that forms the basis for the SAMA evaluation is a new model and stated to represent the current state-of-the-art (Exelon 2013b).

The Level 2 model utilizes a single containment event tree (CET) to assess the accident progression following a core damage event and contains both phenomenological and systemic events. The Level 1 core damage sequences are binned into plant damage states (PDSs), which provide the interface between the Level 1 and Level 2 CET analysis. Each PDS bin is then entered into the CET. The CET is linked directly to the Level 1 event trees and CET nodes are evaluated using supporting fault trees and logic rules.

The result of the Level 2 PRA is a set of 13 release or source term categories, with their respective frequency and release characteristics. The results of this analysis for Byron are provided in Table F.2-8 of the ER (Exelon 2013b). The categories were defined based on the similarity of scenario release characteristics and ultimate containment failure mode. This resulted in six release categories with large early releases (LERs), four with late releases, two with small early releases, and one for an intact containment. The frequency of each release category was obtained by summing the frequency of the individual accident progression CET endpoints binned into the release category. Source terms were developed for each of the thirteen release categories using the results of Modular Accident Analysis Program (MAAP) Version 4.0.6 computer code calculations (Exelon 2013b).

The offsite consequences and economic impact analyses use the MACCS2 code (Chanin and Young 1998) to determine the offsite risk impacts on the surrounding environment and public. Inputs for these analyses include plant-specific and site-specific input values for core radionuclide inventory, source term and release characteristics, site meteorological data, projected population distribution (within a 50-mi (80-km) radius) for the year 2046, emergency response evacuation modeling, and economic data. The core radionuclide inventory corresponds to the end-of-cycle values for Byron operating at 3,645 megawatts thermal (MWt). The magnitude of the onsite impacts (in terms of cleanup and decontamination costs and occupational dose) is based on information provided in NUREG/BR-0184 (NRC 1997c).

In the ER, Exelon estimated the dose to the population within 50 mi (80 km)) of the Byron site to be approximately 0.354 person-sievert (Sv) (35.4 person-rem) per year (Exelon 2013b). In addition, Exelon estimated the annual offsite economic cost impact to be $255,000 per year. The breakdown of the total population dose and offsite economic cost by containment release mode is summarized in Table F–2. Late failures due to containment overpressure events (such as loss of containment heat removal due to loss of power or cooling water) and large early release frequency (LERF) accidents caused by unisolated interfacing-systems loss-of-coolant accident (ISLOCA) dominate the population dose risk at Byron. Late containment overpressure failures dominate the offsite economic cost impact.

Table F–2. Breakdown of Population Dose and Offsite Economic Cost by Containment Release Mode [a]

Containment Release Mode	Population Dose (Person-Rem [b] Per Year)	Percent Contribution	Offsite Economic Cost ($/year)	Percent Contribution
Containment overpressure (late)	28.3	80	222,700	88
ISLOCA	4.42	12	11,800	5
SGTR	2.16	6	17,600	7
Containment isolation failure	0.34	<1	1660	<1
Containment intact	0.13	<1	120	<1
CFE	0.09	<1	580	<1
Basemat melt-through (late)	0.02	<1	40	<1
Total[c]	**35.5**	**100**	**255,000**	**100**

[a] Values in table derived from Table F.3-9 of the ER.

[b] One person-rem = 0.01 person-Sv.

[c] Column totals may be different because of rounding.

Key: CFE = early containment failure; ER = Environmental Report; ISLOCA = interfacing-systems loss-of-coolant accident; SGTR = steam generator tube rupture; Sv = sievert

F.2.2 Review of Exelon's Risk Estimates

Exelon's determination of offsite risk at the Byron site is based on the following major elements of analysis:

(1) the Level 1 risk model that supersedes the 1994/1997 IPE submittals (ComEd 1994, 1997), a new interim internal fire analysis and the seismic and other external event analyses of the 1996 IPEEE submittal (ComEd 1996);

(2) the new Level 2 risk model; and

(3) the MACCS2 analyses performed by Exelon to translate fission product source terms and release frequencies from the Level 2 PRA model into offsite consequence measures.

Each of these analyses was reviewed by the NRC staff to determine the acceptability of the Byron's risk estimates for the SAMA analysis, as summarized below.

F.2.2.1 Internal Events CDF (PRA Level 1) Model

The NRC staff's review of the Byron IPE is described in an NRC letter dated December 3, 1997 (NRC 1997b). Based on a review of the original and modified IPE submittal, the NRC staff concluded that the Byron IPE has met the intent of generic letter (GL) 88-20 (NRC 1988). The NRC staff review concluded that, while Exelon did not provide a definition of vulnerability, Exelon identified one "potential vulnerability" and one enhancement were. These are discussed in Section F.3.2.

There have been numerous revisions to the Byron PRA since the original 1994 IPE submittal. A listing of the complete revision history of the Byron PRA since the original IPE submittal was provided in the ER (Exelon 2013b) and is summarized in Table F–3 below. A comparison of the internal events CDF between the 1997 modified IPE and the current PRA model indicates there has been essentially no change in the total CDF (from 4.0×10^{-5} per year for both units to 4.0×10^{-5} per year for Unit 1 and 3.8×10^{-5} per year for Unit 2).

The CDF value from the 1997 modified IPE (4.0×10^{-5} per year) is in the middle range of the CDF values reported in the IPEs for Westinghouse four-loop plants. Figure 11.6 of NUREG-1560 shows that the IPE-based total internal events CDF for Westinghouse four-loop plants ranges from 2×10^{-6} per year to 2×10^{-4} per year, with an average CDF for the group of 6×10^{-5} per year (NRC 1997a). It is recognized that other plants have updated the values for CDF subsequent to the IPE submittals to reflect modeling and hardware changes. The current internal events CDF results for Byron (4.0×10^{-5} per year for Unit 1 and 3.8×10^{-5} per year for Unit 2) are comparable to results for other plants of similar vintage and characteristics.

The NRC staff considered the peer review performed for the Byron PRA, and the potential impact of the review findings on the SAMA evaluation. In the ER (Exelon 2013b), Exelon briefly described the results of the 1999 Westinghouse Owners Group peer review of Revision 0 of the Byron PRA. Exelon stated that the 27 significance-level A (expected impact to be significantly nonconservative) and -level B (expected impact to be nonconservative but small) facts and observations (F&Os) generated during the peer review have been closed out. The NRC staff requested that Exelon describe what is meant by "closed out," how this is verified, and whether these F&Os were considered in the 2012 self-assessment and the corrections incorporated in the PRA used for the SAMA analysis. In response, Exelon provided a description of the process used to track and close out F&Os as well as other potential model changes. In the ongoing model update process, the model and document changes associated with each F&O, as well as the decision to not change the model or documentation, are reviewed and approved with each official model approval in accordance with Exelon procedures. The approved dispositions of all peer review F&Os were incorporated in the SAMA PRA. Exelon stated that "changes due to the peer review F&Os were fully considered as part of the 2012 self-assessment" (Exelon 2014).

The NRC staff has determined that Exelon's disposition of the peer review findings is consistent with the guidance in Nuclear Energy Institute (NEI) 05-01 (NEI 2005) and that the final resolution of the findings provides reasonable assurance of minimal impact to the results of the SAMA analysis.

Table F–3. Summary of Major PRA Models and Corresponding CDF and LERF Results [a]

PRA Model	Summary of Significant Changes From Prior Model	CDF (per year)		LERF (per year)	
		Unit 1	Unit 2	Unit 1	Unit 2
Original IPE (4/1994)	IPE Submittal	3.1×10^{-5} (same model)		2.7×10^{-6} (same model)	
Modified IPE [b] (3/1997)	Numerous modifications based on NRC concerns on Byron IPE similar to those on other Commonwealth Edison IPEs	4.0×10^{-5} (same model)		Not Available	
Revision 0 (10/1999)	Changed PRA model from support state model to linked fault tree model involving extensive changes to all event trees and fault trees Updated all data	5.0×10^{-5}	4.9×10^{-5}	4.5×10^{-6}	4.4×10^{-6}
Revision 1 (10/2000)	The SX pump success criterion was changed from two pumps to one pump.	4.6×10^{-5}	4.5×10^{-5}	5.4×10^{-6}	5.3×10^{-6}
Revision 3a (8/2001)	Revised LOOP/DLOOP Event Tree Revised internal flooding analysis Incorporation of plant modifications to CVCS pump lube oil cooler Incorporation of plant mod that removed AFW pump 1B dependency on instrument air	5.5×10^{-5}	5.5×10^{-5}	6.2×10^{-6}	6.1×10^{-6}
Revision 4 (2/2002)	Significant model enhancements to the following systems: RPS, ESFAS, CCW, PORVs, AFW, and instrument power Updated containment failure likelihood	5.3×10^{-5}	5.2×10^{-5}	5.4×10^{-6}	6.2×10^{-6}
Revision 5 (12/2002)	Changed small LOCA and transient accident modeling Addressed miscellaneous model issues Incorporated updated failure and unavailability data, HEPs and support system initiating event frequencies	4.9×10^{-5}	4.7×10^{-5}	4.4×10^{-6}	4.8×10^{-6}
Revision 5B (6/2003)	Reevaluated the plant-specific data Performed full convergence analysis and a human failure dependency analysis Incorporated new SX success criteria Revised the model so that automatic quantification can be performed using ORAM-Sentinel and PSALINK program	6.2×10^{-5}	6.1×10^{-5}	4.7×10^{-6}	5.5×10^{-6}
Revision 5F (12/2006)	Model revised to incorporate conditional DLOOP for most initiators Updated some LERF binning Changed modeling of ESFAS testing Added RWST switchover channel testing and common cause	5.8×10^{-5}	5.7×10^{-5}	4.7×10^{-6}	5.6×10^{-6}

PRA Model	Summary of Significant Changes From Prior Model	CDF (per year)		LERF (per year)	
		Unit 1	Unit 2	Unit 1	Unit 2
Revision 6C (5/2008)	Extensive model update including changes to AFW success criteria, revisions to human error probability to reflect procedure changes and operator interviews, revised internal flooding analysis, updated data analysis, and changes to ESW and CCW modeling.	$3.6{\times}10^{-5}$	$3.6{\times}10^{-5}$	$2.5{\times}10^{-6}$	$3.1{\times}10^{-6}$
Revision 6E3 (5/2010)	Revised RCP seal LOCA model Incorporated revised feed and bleed success criteria Incorporated AFW unit crosstie modification Revised human reliability assessment	$1.7{\times}10^{-5}$	$1.7{\times}10^{-5}$	$1.1{\times}10^{-6}$	$1.4{\times}10^{-6}$
Revision BB011a (6/2012)	Updated internal flooding analysis Incorporated new data analysis Incorporated new human reliability dependency and preinitiator analysis Removed credit for AFW unit crosstie modification	$4.2{\times}10^{-5}$	$4.0{\times}10^{-5}$	$2.6{\times}10^{-6}$	$3.2{\times}10^{-6}$
Revision BB011b (11/2012)	Improved modeling of ESW and CCW systems Incorporated new operator actions for use of ESW and CCW systems	$4.0{\times}10^{-5}$	$3.8{\times}10^{-5}$	$2.6{\times}10^{-6}$	$3.2{\times}10^{-6}$
Revision BB011b1 (12/2012)	LERF model replaced with Level 2 model based on methodology of WCAP-16341-P	$4.0{\times}10^{-5}$	$3.8{\times}10^{-5}$	$1.1{\times}10^{-6}$	$1.0{\times}10^{-6}$

[a] Except for Modified IPE information, information in table is based on ER Table F.2-1 with some intermediate models not included.

[b] Information from ComEd 1997.

KEY: AFW = auxiliary feedwater; CCW = component cooling water; CDF = core damage frequency; CVCS = chemical and volume control system; DLOOP = dual unit loss of offsite power; ER = Environmental Report; ESFAS = engineered safety features actuation system; ESW = emergency service water; HEP = human error probability; IPE = individual plant examination; LERF = large early release frequency; LOCA = loss-of-coolant accident; LOOP = loss of offsite power; NRC = U.S. Nuclear Regulatory Commission; PORV = power-operated relief valve; PRA = probabilistic risk assessment; RCP = reactor coolant pump; RPS = reactor protection system; RWST = refueling water storage tank; SX = essential service water; WCAP = Westinghouse Commercial Atomic Power

The NRC staff noted in an RAI that ER Table F.2-1, describing changes made to each PRA revision, states PRA Revision 5A "[r]evised the model and data to address the PRA quality issues raised by CR#00142080 (1/30/03) against Rev. 5 model." The NRC staff requested Exelon to identify the underlying quality process issues and the corrective actions taken. In response to the RAI Exelon stated:

> The underlying process issue that allowed these technical quality issues to occur was a premature approval of the model prior to full review as required by the work process procedure. Exelon T&RM [Training and Reference Material] ER-AA-600-1015, 'FPIE [full power, internal event] PRA Model Update,' provides

> specific process and review criteria for a new model to be officially approved. [Exelon 2014]

Exelon further stated:

> This process was not followed adequately for Revision 5, resulting in the CR [condition report]. To help ensure that the review items are performed prior to model approval, the Quantification Notebook for each official model of record (including the current model of record) now includes confirmation that the reviews required by ER-AA-600-1015 were performed to check for these and other quality issues. The Quantification Notebook documenting the listed reviews is internally independently reviewed. Signatures of the author, reviewers, and approver confirm this review has been performed, and approval of the Quantification Notebook signifies official approval of the updated model. [Exelon 2014]

Exelon indicated that there had been several self-assessments of the Byron PRA, with the latest in 2012 of Revision BB011a, against the Capability Category II requirements of the 2009 revision of the American Society of Mechanical Engineers (ASME) PRA standard (ASME and ANS 2009). In response to an NRC staff RAI concerning this self-assessment, Exelon indicated that the self-assessment considered the guidance in Regulatory Guide 1.200, Rev. 2 (NRC 2009), and was performed consistent with the NEI 00-02 (NEI 2006) self-assessment process (Exelon 2014).

This self-assessment identified two supporting requirements (SRs) that were classified as not being met and 22 that were considered to meet only the Capability Category I requirements. The ER provided a tabulation of the issues related to the SRs that did not meet Capability Category II and the potential impact on the SAMA analysis. All but four of the SRs not meeting Capability Category II were associated with requirements for the LER analysis. This was a result of the self-assessment being performed on the BB011a LERF-only model. These LER issues were addressed in a subsequent assessment as discussed in Section F.2.2.3 below. For the four non-LER issues identified in the self-assessment, Exelon concluded that not meeting the Capability Category II is either conservative or is a small contributor to plant risk and, therefore, requirements would have no meaningful impact on the SAMA analysis. Based on this assessment by Exelon, the NRC staff concludes that meeting the Capability Category I requirements is reasonable for the SAMA evaluation.

The NRC staff noted in an RAI that the list of CDF contribution by initiating event (see Table F–1 above) included a contribution due to a loss of AP but did not explicitly include a contribution due to a loss of offsite power (LOOP) (NRC 2014). Exelon indicated that the loss of auxiliary power (AP) is a loss of an internal AP bus and is modeled the same as the loss of any other support system. The LOOP contribution is included in the “Other” category and is 1.3 percent and 0.9 percent of the total internal events CDF for Units 1 and 2, respectively. These values are for the LOOP initiating event only and do not include the contributions from LOOP that are the consequences of other initiating events. Both single-unit LOOP and dual unit loss of offsite power (DLOOP) events are included in the Byron PRA (Exelon 2014).

The freeze date for the inclusion of plant-specific data for the model was December 2010. In response to an NRC staff RAI concerning actual or planned changes to Byron hardware or operation since the freeze date, Exelon listed a number of modifications being considered, all of which were considered as SAMAs in the license renewal analysis. In addition Exelon stated that “no potential changes in fuel cycle or fuel management are known that would affect the SAMA analysis” (Exelon 2014).

As indicated at the November 2013 audit and stated in an RAI response (Exelon 2014), Exelon is planning to install no-leakage reactor coolant pump (RCP) seals at Byron. This planned change is not included in the baseline SAMA analysis but is evaluated as a candidate SAMA.

In response to an NRC staff RAI to identify the systems that are shared or can be crosstied between units and describe the modeling, including the treatment of unavailability during outages of the other unit, Exelon indicated that the service water (SW), CCW, auxiliary feedwater (AFW), auxiliary electric power, DC power and instrument air/service air systems are shared or could be crosstied between Byron units and stated that:

> The Byron PRA is a fully integrated two-unit model, so all components from each unit and those shared between units are explicitly modeled. Unit-specific components which can be used by the opposite unit are linked into the opposite unit's fault tree logic structure.

Further, it is indicated that unavailability is modeled with both normal maintenance terms as well as outage maintenance terms for all shared components except those needed during normal full power and outage operations. The normal unavailability is based on unavailable hours during normal power operation while the outage unavailability is based on unavailable hours during an outage and total time (Exelon 2014).

During the concurrent reviews of the Byron ER SAMA analysis and that from the very similar Braidwood Station (Exelon 2013a), the NRC staff noted some differences in PRA results between the two sites. In an RAI, the NRC staff asked Exelon to explain the reasons for these differences, and whether the reasons suggest design or operating changes that might be cost-beneficial for one site or the other (NRC 2014). For sequences resulting from RCP seal LOCAs following loss of CCW with failure to establish emergency core cooling system (ECCS) recirculation cooling but with successful cooldown and depressurization, for which the Byron CDF is considerably larger than that for Braidwood, Exelon indicated that the difference is due to a different normal valve alignment at Byron which requires additional operator actions (Exelon 2014). For sequences resulting from random nonisolable small LOCAs with failure to establish ECCS recirculation cooling but with successful cooldown and depressurization, for which the Braidwood CDF is considerably larger than that for Byron, Exelon indicated that the difference is primarily because at Braidwood the SX007 SW valves must be throttled open to establish an appropriate flow rate through the component cooling heat exchangers (HXs). This requirement results from SW's being taken from Lake Michigan whose water temperature varies throughout the year. At Byron, the SX007 valves do not need manipulation during an accident (Exelon 2014). The potential for SAMAs suggested by these differences is discussed in Section F.3.2.

The NRC staff concludes that the internal events Level 1 PRA model is of sufficient quality to support the SAMA evaluation based on the following:

- An early revision of the Byron internal events PRA model was peer-reviewed.
- A more recent revision was subjected to a self-assessment using the 2009 revision of the ASME PRA standard and the guidance in Regulatory Guide 1.200, Revision 2. The self-assessment was performed consistent with the NEI 00-02 self-assessment process, and the review findings were adequately resolved.
- Exelon has satisfactorily addressed NRC staff questions regarding the PRA.

F.2.2.2 External Events

As indicated above, the Byron PRA used for the SAMA analysis does not include external events. In the absence of such an analysis, Exelon used the Byron IPEEE and other analyses to identify the highest risk accident sequences, to identify the potential means of reducing the risk posed by those sequences, and to estimate the benefit of potential SAMAs. This is discussed below and in Section F.3.2.

The Byron IPEEE was submitted in December 1996 (ComEd 1996), in response to Supplement 4 of GL 88-20 (NRC 1991). The submittal included a seismic margin assessment (SMA), a fire assessment using the Electric Power Research Institute (EPRI) fire-induced vulnerability evaluation (FIVE) guidance (EPRI 1992), and a screening analysis for other (high winds, floods and other (HFO)) external events. ComEd did not identify any vulnerabilities in the seismic, fire, or HFO areas. However, during ComEd's IPEEE development several seismic issues were identified as "outliers." Outliers are plant equipment or component conditions that did not meet one or more of the seismic screening criteria and, therefore, required further evaluation during the IPEEE. These outliers were considered in the SAMA evaluation, as discussed further below. In its IPEEE safety evaluation report (SER) (NRC 2001), the NRC staff concluded that the applicant's IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities for external events and, therefore, that the Byron IPEEE has met the intent of Supplement 4 to GL 88-20.

The Byron IPEEE seismic analysis was a focused-scope SMA following NRC guidance (Chen et al. 1991; NRC 1991). The SMA approach is deterministic in nature and does not result in probabilistic risk information. The SMA was performed using a Safe Shutdown Equipment List (SSEL) with plant walkdowns in accordance with the guidelines and procedures documented in EPRI Report NP-6041-SL (EPRI 1991). Two success paths, each capable of mitigating the effects of a seismically induced small break LOCA, were identified based on a review of the guidance and plant documentation. The components on the SSEL were then evaluated for seismic capacity.

The components and associated structures in which they are housed were evaluated based on the screening criteria of NP-6041-SL. The review of major structures was based primarily on a review of the design bases augmented by a walkdown to identify any anomalous conditions. Masonry block walls were evaluated and qualified to the seismic design basis loads in compliance with the plant's seismic evaluation criteria. Mechanical and electrical equipment that did not meet the screening criteria were considered SMA outliers. If the equipment had anchorage that was not judged robust by the walkdown team, the high confidence in low probability of failure (HCLPF) anchorage evaluation was calculated to obtain an anchorage seismic capacity.

A total of 116 outliers were identified (NRC 2001). The majority of the outliers involve seismic interaction concerns that were resolved through some corrective actions. Others were resolved either by Conservative Deterministic Failure Margin capacity analysis to show the capacity well beyond review-level earthquake demand or by maintenance or modifications. These outliers were considered further in the Phase I SAMA identification discussed in Section F.3 below.

For the purposes of the SAMA evaluation, Exelon assumed a seismic CDF of 1×10^{-6} per year in the development of the external events multiplier (Exelon 2013b). Since the SMA approach used in the IPEEE does not involve the determination of seismic CDF and Exelon did not provide a basis for the value used, the NRC staff asked Exelon to consider the impact on the SAMA analysis if a seismic CDF from the generic issue (GI) 199 risk assessment (NRC 2010b) for the Byron site were used. Exelon indicated that, if the weakest link seismic CDF value (5.8×10^{-6} per year) from GI 199 were used, the external events multiplier would increase from 2.5 to 2.6 and reevaluated the SAMAs using this multiplier (Exelon 2014). This is discussed in more detail below.

The Byron IPEEE included an internal fire analysis employing EPRI's FIVE methodology (EPRI 1992). The NRC's IPEEE SER for Byron reports a total fire CDF of 5.0×10^{-6} per year for Unit 1 and 6.1×10^{-6} per year for Unit 2 (NRC 2001). However, the IPEEE fire analysis has been superseded by the 2009 Byron fire PRA, which Exelon states to be an interim implementation of NUREG/CR-6850 (NRC 2005a), given that not all tasks identified in NUREG/CR-6850 (NRC 2005a) are completely addressed or implemented in the model. The total fire CDF for Unit 1 was reported in the ER to be 5.39×10^{-5} per year, which is an order of magnitude greater than that reported in the IPEEE SER. The Unit 2 CDF was not reported since the Unit 2 fire model had not been developed to the same degree as the Unit 1 model (this is discussed further below). While the Byron fire PRA is a risk assessment as compared to the IPEEE fire analysis, which is a screening analysis, it was not used in the SAMA analysis to estimate the risk reduction of individual SAMAs. Rather, the Byron fire PRA was used in the SAMA analysis for determining the fire contribution to the external events multiplier, as well as for identifying potential SAMAs to mitigate the internal fire risk.

Exelon indicated that this was because the fire model is not fully integrated with the most recent Level 2 and 3 analyses and is also based on Revision 6C of the internal events PRA rather than the current Revision BB11b1 model used for the internal events SAMA analysis.

In response to an NRC staff RAI that asked for more information on the quality and development status of the 2009 Byron fire PRA, Exelon indicated that the fire PRA development tasks do not have any specific quality assurance activities (Exelon 2014). However, internal processes are used to ensure that the tasks are being performed and reviewed by knowledgeable personnel. This is accomplished by the use of certification guides in addition to each document's having three levels of signatures: preparer, reviewer, and approver. In addition, Exelon briefly discussed several conservatisms and nonconservatisms in the current model. The major conservatism identified is in the fire modeling task, which uses generic treatments of the zone of influence and gives no credit for fire severity. The nonconservatisms identified include not accounting for the effects of hot gas layers and the limited modeling of multiple spurious operations. The human reliability analysis (HRA) is identified as having potentially both conservative and nonconservative impacts on the results. A flowchart method is used for determining the human error probabilities (HEPs). The HEPs are generic in nature and modified based on certain parameters that may not be accurate given the actual fire. In addition, the HEPs may be higher due to the unavailability of cues to give the operators a chance to respond to the event or, in some cases, timing constraints (Exelon 2014).

The NRC staff notes that, while the 2009 Byron fire PRA is still under development and has not been peer reviewed, the SAMA evaluation should be performed using the best available information on risk insights. The NRC staff concludes that the use of the fire PRA model provides an acceptable basis for identifying and evaluating SAMA candidates based on the following criteria:

- The 2009 Byron fire PRA model is a more current analysis of the fire risk at Byron than the IPEEE fire analysis and, therefore, is the best currently available fire risk information.
- The reported fire risk is substantially higher for the fire PRA model than that from the IPEEE.
- The fire PRA model is being developed in accordance with NUREG/CR-6850,.

The major fire core damage contributors for each unit (defined as having a CDF greater than 1×10^{-6} per year) are listed in Table F–4. This information was used by Exelon to identify potential SAMAs for the fire events and to evaluate the benefit of any SAMA uniquely directed at reducing the fire risk. This is discussed in Sections F.3 and F.4 below.

Table F–4(a). Major Byron Unit 1 Contributors to Fire CDF

Fire Zone	Fire Zone Description	CDF (per year)
11.3-0	Auxiliary building general area, Elv. 364	1.4×10^{-5}
11.6-0	Auxiliary building general area, Elv. 426	6.0×10^{-6}
5.2-1	Div. 11 ESF switchgear room	4.2×10^{-6}
11.3-1	Unit 1 containment pipe penetration area	4.0×10^{-6}
11.4-0	Auxiliary building general area, Elv. 383	3.8×10^{-6}
11.4C-0	Radwaste and remote shutdown panel control room	3.6×10^{-6}
11.6C-0	Auxiliary building laundry room	1.8×10^{-6}
17.2-2	SX cooling tower, div. 11/21	1.6×10^{-6}
18.14A-1	SX tower electrical equipment room, div. 12	1.5×10^{-6}
5.1-1	Div. 12 ESF switchgear room	1.3×10^{-6}
3.4A-1	Unit 1 cable riser area, Elv. 451	1.2×10^{-6}
18.3-1	Unit 1 main steam and AFW pipe tunnel	1.1×10^{-6}

Key: AFW = auxiliary feedwater; CDF = core damage frequency; div. = Division; Elv. = Elevation; ESF = engineered safety feature; SX = essential service water

Table F–4(b). Major Byron Unit 2 Contributors to Fire CDF

Fire Zone	Fire Zone Description	CDF (per year)
11.6-2	Div. 22 containment electrical penetrations area	2.1×10^{-5}
11.4-0	Auxiliary building general area, Elv. 383	1.4×10^{-5}
11.6-0	Auxiliary building general area, Elv. 426	1.1×10^{-5}
5.2-2	Div. 21 ESF switchgear room	6.5×10^{-6}
11.4c-0	Radwaste and remote shutdown panel control room	3.6×10^{-6}
1-2	Unit 2 Containment	2.0×10^{-6}
11.3f-2	SI pump 2B room	1.8×10^{-6}
11.3g-2	Centrifugal charging pump 2B room	1.8×10^{-6}
18.14A-1	Fuel handling building	1.8×10^{-6}
17.2-2	SX Cooling Tower, Div. 11/21	1.7×10^{-6}
11.3a-2	SI pump 2A room	1.7×10^{-6}
5.1-2	Div. 22 ESF switchgear room	1.6×10^{-6}
5.5-2	Unit 2 auxiliary electric equipment room	1.5×10^{-6}
3.2-0	Auxiliary building, Elv. 439	1.2×10^{-6}

Key: CDF = core damage frequency; div. = Division; Elv. = Elevation; ESF = engineered safety feature; SI = safety injection; SX = essential service water

As stated above, the total fire CDF for Unit 1 was reported in the ER to be 5.39×10^{-5} per year. The Unit 2 CDF was not reported or used since the Unit 2 fire model had not been developed to the same degree as the Unit 1 model. In response to an NRC staff RAI on the development status of the Unit 2 fire PRA model, Exelon explained that at the time the SAMA analysis was performed, the Byron fire model was in the process of being refined to remove model conservatisms, including such changes as taking credit for hot short probabilities to more accurately represent the potential for spurious operation, and refining the cable impacts based on additional circuit analysis. These refinements have been completed for the Byron Unit 1 fire PRA, but not for the Byron Unit 2 fire PRA. Based on this, and the similarities of the two units, the Unit 1 fire CDF was considered the most representative fire CDF for Byron (Exelon 2014).

The NRC staff notes that a SAMA evaluation should be performed using the best available risk information. Based on this, and the similarities between the two units, the NRC staff has determined that the fire CDF of 5.39×10^{-5} per year is appropriate for use in the SAMA analysis for both Units 1 and 2.

The Byron IPEEE analysis of high winds and tornadoes, external floods, and transportation and other nearby facility accidents (HFO events) followed the screening and evaluation approaches specified in Supplement 4 to GL 88-20 (NRC 1991). For these events, the IPEEE concluded that the Byron design conforms to the 1981 Standard Review Plan criteria (NRC 1981), and, therefore, the contribution to CDF from these events meets the IPEEE screening criterion of 1×10^{-6} per year in NUREG–1407 (Chen et al. 1991). No vulnerabilities or enhancements were identified.

Based on the aforementioned results, Exelon indicated in the ER that the total external events CDF is approximately 5.8×10^{-5} per year (based on a seismic CDF of 1.0×10^{-6} per year, a fire CDF of 5.4×10^{-5} per year, a high wind CDF of 1.0×10^{-6} per year, an external flooding CDF of 1.0×10^{-6} per year ,and transportation and other nearby accidents CDF of 1.0×10^{-6} per year), which is approximately 1.5 times the internal events CDF of 4.0×10^{-5} per year. The total CDF (internal and external events) is then approximately 9.8×10^{-5} per year or 2.5 times the Unit 1 internal events CDF. This multiplier was used in the SAMA analysis in the ER to account for the impact of external events on the benefits determined from the internal events PRA.

As discussed above, the GI 199 risk assessment gives a seismic CDF for Byron of 5.8×10^{-6} per year. Use of this value yields a total external events CDF of 6.3×10^{-5} per year and a total internal plus external events CDF of approximately 1.0×10^{-4} per year, which is approximately 2.6 times the Unit 1 internal events CDF. In response to an NRC staff RAI, Exelon stated that it used this higher multiplier in an updated cost-benefit analysis (Exelon 2014).

The NRC staff finds that the applicant's conclusion concerning the contribution from seismic, fire, and HFO events to the multiplier used to represent the impact of external events is acceptable and finds that the applicant's use of a multiplier of 2.6 reasonably accounts for external events in the SAMA evaluation. This is discussed further in Section F.6.2.

F.2.2.3 Level 2 Fission Product Release Analysis

The NRC staff reviewed the general process used by Exelon to translate the results of the Level 1 PRA into containment releases, as well as the results of the Level 2 analysis, as described in the ER and in response to NRC staff RAI (Exelon 2014). The current Level 2 model is essentially a completely new model replacing the prior LERF model and developed specifically for the SAMA analysis. Exelon states that the current Byron Level 2 model is a state-of-the-art Level 2 analysis structure designed to address the Category II requirements of Regulatory Guide 1.200 (NRC 2009) and the ASME PRA Standard (ASME 2009).

The Level 2 model is stated to be generally consistent with the "Simplified Level 2 Modeling Guidelines," WCAP-16341-P (Westinghouse 2005). This WCAP provides a common, standardized method for pressurized-water reactors (PWRs) with large, dry containments to produce an analysis that generally meets Capability Category II of the ASME PRA standard. The guidance particularly addresses the latest understanding for induced SGTRs, direct containment heating, and other important Level 2 phenomena. While the WCAP is focused on modeling the LERF for the ASME standard, it includes guidance for including intact, small, and late releases to provide a more complete, though still standardized, Level 2 analysis.

In response to an NRC staff RAI that asked the applicant to identify areas where the Byron model differs from that in WCAP-16341-P, Exelon indicated that the differences include (Exelon 2014):

- No credit for recovery of alternating current power or diesel generator repair after core damage is given.
- Modeling of potential hot leg rupture following an induced tube rupture, such that the release to the environment is substantially reduced, based on recent research results from the State-of-the-Art Reactor Consequence Analysis project (Bixler et al. 2013).
- A combined CET is used rather than separate SBO and non-SBO CETs. This is a modeling choice and has no effect on the overall model since recovery of offsite power is not credited.

- Operator action is credited to maintain a sufficient water pool over the steam generator (SG) tubes to scrub releases in SGTR events. While not specifically included in the WCAP methodology, WCAP-16341-P does identify that this type of scrubbing is possible.

As described in Section F.2.3.1 of the ER, PDSs provide the interface between the Level 1 and Level 2 analyses. Each Level 1 accident sequence that leads to core damage consists of a unique combination of an initiating event followed by the success or failure of various plant systems (including operator actions). The Level 1 sequences that result in core damage are grouped into PDS bins. Each bin 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 safeguards systems, and the potential for mitigating the potential radiological source terms are similar.

The PDS bins for Byron are characterized by the status of containment bypass due to SGTR or ISLOCA, reactor coolant system pressure, and the availability of feedwater (FW) and AFW.

For Byron, a single detailed CET, which contains both phenomenological and systemic events, assesses the accident progression following a core damage event and analyzes each PDS bin as a group. The Byron CET (shown in ER Figure F.2-4) is stated to be based on the CETs provided in WCAP-16341-P. While the function of the CET is essentially the same as the WCAP CETs, some changes were made to accommodate the capabilities and features of the Byron PRA model. The event tree begins with one or more core damage sequences and then asks a number of questions to determine the type of release, if any, that occurs. Each question is modeled as a top event in the event tree, and the outcome is based on previous work for Byron (including logic taken from the existing model), recent accident progression research, and the guidance provided in the WCAP.

The NRC staff noted in an RAI that ER Section F.2.3.2 indicated that containment failure due to direct containment heating is “0.000” and asked the applicant to clarify how this and other early containment failure (CFE) probabilities are included in the Level 2 models (NRC 2014). In response to the RAI, Exelon indicated that the 0.000 containment failure probability is not a typo, but is the value reported from WCAP-16341-P, which in turn quotes the value from NUREG/CR-6338, *Resolution of Direct Containment Heating Issue for all Westinghouse Plants with Large Dry Containments or Subatmospheric Containments* (Pilch et al. 1996). The WCAP notes that the NUREG provides only three significant digits. The 0.000 value applies to all sequences and all combinations of hydrogen burns, steam explosion, and direct containment heating. Therefore, the probability of CFE at Byron or Braidwood is negligible for any sequence. However, in order to maintain flexibility in the model for sensitivity analyses, the CFE probability is maintained in the model and assigned a probability of 0.001 for any cause or combination of causes (Exelon 2014).

Each CET end state represents a radionuclide release to the environment and is assigned to a release category. Four general release categories were defined: (1) intact, (2) late release, (3) small early release, and (4) LER. Because there are a large number of Level 2 sequences that contribute to each general release category with varying release characteristics, the general release categories are subdivided into 13 detailed release categories.

The LER categories are for the containment bypass or failure conditions that lead to the release: unisolated ISLOCAs, containment isolation failures, CFEs, noninduced SGTRs with and without FW, and pressure- or thermal-induced SGTRs. The late release categories are for containment overpressure failure and basemat melt-through each with or without FW. The small early release categories are for SGTRs with FW available resulting in water level above the SG tubes, and thermally induced SGTRs shortly followed by hot-leg failure.

Exelon developed the accident progression and associated release characteristics for each release category, by using the results of MAAP Version 4.0.6 computer code calculations. A representative sequence was selected for each detailed release considering both the likelihood of the scenario and its potential consequences. Since source terms are not always available for each sequence making up a release category, the selection of the representative sequences were based on judgment as to the potential consequences. Exelon stated that the sequence that is judged to be associated with a higher potential source term is used as the representative sequence unless there is another sequence that accounts for a majority of the release category frequency and the sequence with the “higher” source term accounts for less than about 10 percent of the release category frequency. In those cases, the “majority” sequence would be chosen as representative (Exelon 2013b). Table F.2-6 of the ER describes the representative sequence used for each release category. Table F.3-8 of the ER describes and justifies the MAAP case for each representative sequence and provides the resulting key event timings. In response to an NRC staff RAI, Exelon stated that the input for the MAAP cases specified the fission product mass as recommended by the MAAP Users Group Bulletin, “MAAP-FLASH #68” (Exelon 2014).

The above listed tables indicate that for several release categories the run duration of the MAAP analysis was quite long (200, 800, and 1,600 hours). It was stated that this duration was necessary to achieve a plateau of the release fractions, with primary attention paid to cesium iodide and cesium hydroxide release fractions. In response to NRC staff RAI that asked Exelon to explain the reason for the longer duration and to identify conservatisms in the analysis, Exelon indicated that the run times for various MAAP calculations were established based on the timing for the onset of core damage, the timing for either containment failure or containment bypass, and consideration of revaporization of fission products that initially deposited within the reactor coolant system (RCS), particularly on the SG tubes which, after the SG dries out and the tube temperature increases, the deposited fission products become available for release late in the event. The run times were selected to make sure to capture this revaporization phenomenon (Exelon 2014).

In response to the RAI, Exelon provided plots of the cesium iodide release as a function of time for a number of release categories, which showed that in many cases a stable total release from the containment is achieved well before the end of the run. For the dominant release category (LATE-CHR-NOAFW), which contributes 50 percent of the population dose risk and 73 percent of the offsite economic cost risk (OECR) the cesium iodide reaches a stable value at 600 hours. For cesium hydroxide (which is stated by Exelon to be the primary driver for long-term dose and costs), the release is slower, and the release fraction is still increasing at a slow rate even at 1,600 hours.

The NRC staff notes that the above cited times of 600 hours (25 days) and 1,600 hours (67 days) are longer than the time (generally assumed to be less than 100 hours) by which it might reasonably be expected that additional onsite and offsite resources would be available to mitigate the releases. This has a significant impact on the release fractions. For example, from Exelon’s RAI response (Exelon 2014), for the dominant release category, at 72 hours, or 3 days, after declaration of a general emergency, the cesium iodide release fraction is 37 percent of the value used in the consequence analysis, while the cesium hydroxide release fraction is 7 percent of the value used in the consequence analysis. Alternatively, if the releases were terminated at 144 hours, or 6 days, after declaration of a general emergency, the cesium iodide release would be 63 percent and the cesium hydroxide release would be 16 percent of the values used in the consequence analysis for the dominant release category. Use of these lower release fractions would result in a significant reduction in both population dose risk and OECR.

In response to an NRC staff's RAI that asked Exelon to identify the major factors that contribute to the OECR and to discuss their realism and conservatism, Exelon, in addition to discussing the conservatism involved in using the release fractions for very long run times, identified conservative modeling involving the chemical form of cesium. NUREG/CR-7110 (Bixler et al. 2013) indicates that only a small fraction of the cesium is in the form of cesium iodide and that the dominant chemical form will be cesium molybdate with the remaining cesium in the form of cesium hydroxide. The Byron SAMA analyses assume that the dominant cesium chemical form is cesium hydroxide. Cesium molybdate has a very low vapor pressure and would therefore be expected to remain deposited on structures (e.g., the tubes in an SG) for a longer time relative to cesium hydroxide. Exelon concluded that the result of this assumption is a conservative SAMA assessment because the release fraction for cesium molybdate would be lower than that for cesium hydroxide (Exelon 2014).

The NRC staff noted in an RAI that the analysis of sequences involving containment isolation failure did not allow for CFE due to such phenomenology as hydrogen explosion or direct containment heating (NRC 2014). In response to the RAI, Exelon indicated that while hydrogen explosion and direct containment heating are potential failure modes for the containment isolation failure sequences (release category LERF-CI), the probability of CFE due to these mechanisms is 1×10^{-3}. While the CFE cesium iodide release fraction may be about 20 times larger than the cesium iodide release fraction for containment isolation, the frequency is 1,000 times less. Further, the potential contribution from the fraction of isolation failures that result in CFE represent only about 1 percent of the other CFE frequency (release category LERF-CFE). Rebinning the CFE contributions from the LERF-CI release category into the LERF-CFE release category results in no measurable change to the reported population dose risk and OECR values and, therefore, would have no impact on the SAMA analysis (Exelon 2014).

The results of the Level 2 analysis are provided in ER Tables F.2-8 (release category frequencies) and F.2-7 (timing and magnitude of release). The NRC staff noted in an RAI that, while the release category frequencies for the two units are generally very close (within about 10 to15 percent of each other), for one risk important release category (late containment failure without FW (LATE-CHR-NOAFW)) the Unit 1 frequency is 20 percent more than that for Unit 2 (NRC 2014). In response to the RAI Exelon explained that the difference in Unit 1 and Unit 2 results for LATE-CHR-NOAFW is related to the assumed default configurations for the two units. For Unit 1, the assumed SX pump configuration models pump 1A in standby and pump 1B running. For Unit 2, the opposite configuration is modeled, with pump 2A running and pump 2B in standby. Because other pumps have the same default configurations in both units, unique train-based power failures can occur at Unit 1 that do not occur at Unit 2. This can result in slightly different sequences because of power dependency failures such as seen here. Unit 1 has the higher frequency and was used for the purposes of the SAMA analysis (Exelon 2014).

In response to an NRC staff RAI that asked Exelon to describe the steps taken to ensure the technical adequacy of the revised Byron Level 2 PRA model, Exelon indicated, for the initial completion of the updated Level 2 model included in Revision BB011b1 of the PRA, an internal review was conducted examining accident sequence modeling, fault tree modeling, and cutset reviews. The documentation of the BB011b1 model also included a self-assessment and roadmap against Capability Category II of the ASME PRA Standard. This self-assessment and roadmap concluded that all applicable LERF SRs were met at Capability Category II. The signature of the preparer and the reviewer confirm the internal review and agreement with the conclusion of the self-assessment and roadmap. The new Level 2 model replaced the simplified, and generally conservative, previous LERF model. Reductions in LERF come from several improvements, including credit for an operator action to keep an SG full to scrub a release from an SGTR and reduced CFE probabilities (Exelon 2014).

The NRC staff reviewed the Level 2 methodology and determined that Exelon satisfactorily addressed NRC staff RAIs. While the updated Level 2 model has not been peer reviewed, Exelon assessed the Level 2 model against the LERF SRs of the ASME PRA standard and determined that all applicable SRs meet the Capability Category II requirements. Therefore, the NRC staff concludes that the Level 2 PRA is of sufficient quality to support the SAMA evaluation.

F.2.2.4 Level 3 Offsite Consequence Analysis

The NRC staff reviewed the process used by Exelon to extend the containment performance (Level 2) portion of the PRA to an assessment of offsite consequences (Level 3 PRA). This included consideration of the source terms used to characterize fission product releases for the applicable containment release categories and the major input assumptions used in the offsite consequence analyses. The MACCS2 code (Version 1.13.1) was utilized to estimate offsite consequences (Chanin and Young 1998). Plant-specific input to the code includes the source terms for each source term category and the reactor core radionuclide inventory (both discussed above), site-specific meteorological data, projected population distribution within an 50-mi (80-km) radius for the year 2046, emergency evacuation modeling, and economic data. As indicated in the ER, the reactor core radionuclide inventory used in the consequence analysis was based on end-of-cycle power of 3,645 MWt. The current rated power for Byron is 3,586.6 MWt, and the core radionuclide inventory was based on this power (Exelon 2008). Exelon has submitted a license amendment application to the NRC requesting a measurement uncertainty recapture (MUR) power uprate from 3,586.6 MWt to 3,645 MWt (Exelon 2011). The proposed uprate power of 3,645 MWt was included in the MACCS2 analysis by scaling the base core inventory by the power uprate ratio (1.0163). This information is provided in Section 3.5 of Attachment F to the ER (Exelon 2013b). Exelon performed a sensitivity study assuming the current rated power (3,586.6 MWt). The decrease in power of −1.63 percent resulted in a decrease in both population dose risk and cost risk of 1 percent each.

Exelon modeled all releases as being from midheight of the reactor containment building and at10 MW thermal content, except for intact containment (which maintained zero energy). Exelon performed sensitivity studies using zero plume energy (Exelon 2013b). With zero plume heat the dose risk increased approximately 0.2 percent and the cost risk increased approximately 3 percent. Exelon performed sensitivity studies for plume release height and deposition velocity (Exelon 2013b). Release height set to ground level resulted in a decrease in dose risk of 1 percent and a decrease in cost risk of 3 percent. Release height set to the top of containment resulted in an increase in dose risk of 1 percent and an increase in cost risk of 3 percent. The deposition velocity was reduced from 0.01 to 0.005 meter per second (m/s) (0.03 to 0.016 foot per second) (a factor of 2), which resulted in a decrease in population dose risk of 8 percent and decrease in cost risk of 19 percent. In response to an NRC staff RAI, Exelon provided additional values and assumptions associated with the MACCS2 model input, including rainfall, mixing height, building wake effects, plume energy, land fraction, region index, watershed index, growing season, fraction of farmland, and shielding and protection factors (Exelon 2014). Based on the information provided, the staff concludes that the release parameters utilized follow NRC guidance in NEI 05-01 or accepted practices from the NUREG-1150 studies and are therefore appropriate for the purposes of the SAMA evaluation.

Exelon used site-specific meteorological data for the 2008 calendar year as input to the MACCS2 code. The development of the meteorological data is discussed in Section 3.7 of Attachment F to the ER. The data were collected from onsite meteorological monitoring systems. In response to an NRC staff RAI (Exelon 2014), Exelon clarified that only mixing layer height was based on other meteorological data. The mixing layer height was based on an EPA study (Holzworth 1972) and identified in Section F.3.7 of the ER. Missing data were filled in by substituting data from a different elevation, interpolation, power law, or substituting data from the previous or subsequent day. Sensitivity analyses were performed using MACCS2 and the meteorological data for the years 2009 and 2010 (Exelon 2013b). The year 2009 data resulted in a decrease in dose risk of 4 percent and a decrease in cost risk of 2 percent. The year 2010 data resulted in a decrease in dose risk of 1 percent and a decrease in cost risk of 2 percent.

Because the overall results of previous SAMA analyses reviewed by the NRC staff have shown little sensitivity to year-to-year differences in meteorological data, the NRC staff concludes that the use of the 2008 meteorological data in the SAMA analysis is reasonable.

The population distribution the applicant used as input to the MACCS2 analysis was estimated for the year 2046 using year 2000 census data as accessed by SECPOP2000 (Bixler et al. 2003) as a starting point. The transient population was included in the 10-mi (20-km) emergency planning zone (EPZ), and in the population projection from year 2000 to year 2046. In addition, special facilities population was also included in the initial year 2000 population estimate. In response to an NRC staff RAI, Exelon provided the year 2000 transient, special facility, and residential population distributions (Exelon 2014). These are presented in Tables 4b-2 and 4c-2 of the RAI response. A 30-year population growth rate was estimated using the year 2000 SECPOP2000 data and population growth estimates from the Illinois (IDOC 2012), Wisconsin (WDOA 2012), and Iowa (SDCI 2012) county population projections to year 2030. The year 2030 population estimate was then scaled to year 2046 using this growth rate to obtain the distribution in 2046. NRC staff noticed that Section 2.6.1 of the ER contained year 2010 census population, but that the SAMA analysis used year 2000 census data for estimating population growth. In response to an NRC staff RAI, Exelon compared a projected year 2010 population to the recently available year 2010 census population. The projected population within the 50-mi (80-km) radius was slightly less than, but within, 2 percent of the census population (Exelon 2014). The baseline population was determined for each of 160 sectors, consisting of 16 directions for each of 10 concentric distance rings to a radius of 50 mi (80 km) surrounding the site. Individual county growth rates were applied at each grid element. Some grid elements include land from multiple counties. A weighted growth rate was used for those grid elements based on the fraction of land in that grid element associated with each county. Counties that were projected to have negative growth rates were conservatively assumed to have zero growth rates. In response to an NRC staff RAI, Exelon stated that three recently publicized SECPOP2000 code errors were accounted for in the Byron analysis (Exelon 2014). Exelon performed a sensitivity study for the year 2046 population by increasing the population by 30 percent (uniformly). The resulting dose risk increased by 28 percent and cost risk increased by 26 percent. Because population census data and population growth data specific to the location of the Byron plant was used, the NRC staff considers the methods and assumptions for estimating population reasonable and acceptable for purposes of the SAMA evaluation.

The emergency evacuation model was modeled as a single evacuation zone and stated to extend out 10 mi (16 km) from the plant (the EPZ) (ET 2003). Exelon assumed that 95 percent of the population would evacuate. This assumption is conservative relative to the NUREG–1150 study (NRC 1990), which assumed evacuation of 99.5 percent of the population within the EPZ. The evacuated population was assumed to move at an average radial speed of approximately 4.4 m/s (9.8 miles per hour (mph)) with a delayed start time of 115 minutes after declaration of a general emergency (Exelon 2013b). The evacuation speed is a time-weighted average value accounting for season, day of week, time of day, and weather conditions

(ET 2003). A general emergency declaration was assumed to occur when plant conditions degraded to a point that was judged to be a credible risk to the public. In response to an NRC staff RAI, Exelon clarified that the evacuation study (ET 2003) does not associate specific events with the evacuation time study (Exelon 2014). Exelon performed sensitivity studies for the evacuation speed and delay time to evacuation. The evacuation speed was reduced by 50 percent to 2.2 m/s (4.9 mph). The resulting dose risk increased by 2 percent and the change in cost risk was negligible. The evacuation delay time was increased by a factor of 2 to 230 minutes. The resulting dose risk decreased by 0.1 percent and the change in cost risk was negligible. The NRC staff concludes that the evacuation assumptions and analysis are reasonable and acceptable for the purposes of the SAMA evaluation.

Site-specific agriculture and economic parameters were developed manually using data in the 2007 National Census of Agriculture (USDA 2009) and 2007 data from the Bureau of Economic Analysis (BEA 2012) for each of the 21 counties surrounding Byron, to a distance of 50 mi (80 km). Economic values were updated to July 2012 using the consumer price index from the Bureau of Labor Statistics (BLS 2012). The values used for each of the 160 sectors were the data from each of the surrounding counties multiplied by the fraction of that county's area that lies within that sector. Food ingestion was modeled using the new MACCS2 ingestion pathway model COMIDA2 (Chanin and Young 1998). For Byron, approximately 5.6 percent of the total population dose risk is due to food ingestion (approximately 2 person-rem/year) (Exelon 2013b). In response to an NRC staff RAI, Exelon stated that input parameters used were based on food production parameters derived from annual food consumption of an average individual, and that food ingestion dose limits were based on 1998 Food and Drug Administration Guidance (Exelon 2014). Generic economic data that is applied to the region as a whole were revised from the MACCS2 sample problem input in order to account for cost escalation since 1986, the year that input was first specified. A factor of 2.09, representing cost escalation from 1986 to July 2012, was applied to parameters describing cost of evacuating and relocating people, land decontamination, and property condemnation.

Exelon performed a sensitivity study for the economic rate of return, resettlement planning, and generic economic inputs. The rate of return was modified to 3 percent as identified in the NRC's comments (NRC 2005b) on Nuclear Energy Institute (NEI) 05-01, "Severe Accident Mitigation Alternative (SAMA) Analysis Guidance Document" (Revision A) (NEI 2005), and 12 percent, the value used in NUREG-1150 MACCS2 analyses, from the base case of 7 percent, consistent with NRC guidance (NRC 2004). The decrease in rate of return (by approximately 57 percent) resulted in an increase in population dose of 1 percent and a decrease in cost risk of 9 percent. The increase in rate of return (by approximately 71 percent) resulted in a decrease in population dose of 2 percent and an increase in cost risk of 10 percent. Resettlement planning was modified assuming no "Intermediate Phase" and a 1-year "Intermediate Phase" (in lieu of 6 months). The no intermediate phase resulted in an increase in dose risk of 17 percent and a decrease in cost risk of 32 percent. A 1-year intermediate phase resulted in a decrease in dose risk of 14 percent and an increase in cost risk of 35 percent. Key generic economic input parameters to MACCS2 were modified as shown in Table F.7-1 of the ER. In general, the input variables were increased by a factor of 2. The increase in these economic parameters resulted in a decrease in dose risk of approximately 6 percent, and an increase in cost risk of approximately 48 percent.

The NRC staff reviewed the applicant's methods and assumptions for estimating offsite consequences, including the results of several sensitivity analyses on parameter assumptions, and determined that Exelon satisfactorily addressed NRC staff RAIs, that the methods and parameters follow accepted practices, and that offsite consequences are not very sensitive to individual parameter assumptions. Therefore, the NRC staff concludes that the methodology used by Exelon to estimate the offsite consequences for Byron provides an acceptable basis from which to proceed with an assessment of risk reduction potential for candidate SAMAs.

Accordingly, based on the NRC staff's conclusions regarding the internal events CDF model, treatment of external events, Level 2 fission product release analysis, and Level 3 offsite consequence analysis, the NRC staff based its assessment of offsite risk on the CDF, offsite population doses, and offsite economic costs reported by Exelon.

F.3 Potential Plant Improvements

The process for identifying potential plant improvements, an evaluation of that process, and the improvements evaluated in detail by Exelon are discussed in this section.

F.3.1 Process for Identifying Potential Plant Improvements

Exelon's process for identifying potential plant improvements (SAMAs) consisted of the following elements:

- review of the most significant basic events from the current plant-specific PRA including the 2009 Byron fire analysis,
- review of selected cost-beneficial SAMAs from selected plants,
- review of potential plant improvements identified in the Byron IPE and IPEE, and
- insights from the PRA group.

Based on this process Exelon identified an initial set of 30 candidate SAMAs, referred to as Phase I SAMAs. In Phase I of the evaluation, Exelon performed a qualitative screening of the initial list of SAMAs and eliminated SAMAs from further consideration using the following criteria:

- The SAMA is not applicable to Byron plant design.
- The SAMA has already been implemented or its intent met at Byron.
- The SAMA has estimated implementation costs that would exceed the dollar value associated with completely eliminating all severe accident risk at Byron.

Based on this screening, three SAMAs were eliminated leaving 27 for further evaluation. The results of the Phase I screening analysis are provided in Table F.5-3 of the ER (Exelon 2013b). The remaining SAMAs, referred to as Phase II SAMAs, are listed in Table F.6-1 of the ER (Exelon 2013b). In Phase II, a detailed evaluation was performed for each of the 27 remaining SAMA candidates, as discussed in Sections F.4 and F.6 below. To account for the potential impact of external events, the estimated benefits based on internal events were multiplied by a factor of 2.5 as discussed in Section F.2.2.2. Also as discussed in Section F.2.2.2, this multiplier was increased to 2.6 in response to an NRC staff RAI (Exelon 2014).

F.3.2 Review of Exelon's Process

Exelon's efforts to identify potential SAMAs focused primarily on areas associated with internal initiating events. The initial list of SAMAs generally addressed the accident sequences considered to be important to CDF from functional, initiating event, and risk reduction worth (RRW) perspectives at Byron.

Exelon provided in the ER a tabular listing of the Level 1 PRA basic events sorted according to their RRW (Exelon 2013b). The SAMAs impacting these basic events would have the greatest potential for reducing risk. In the ER, Exelon indicates that the review of these events down to an RRW of 1.017 would correspond to a potential benefit of $100,000 if a SAMA to mitigate this event were 100 percent effective. This value is Exelon's estimate of the cost of a procedure change along with any necessary engineering analysis and training. As Exelon noted, this value of the RRW does not include the potential impact of external events, because the Byron fire results were reviewed separately for potential SAMAs since the fire model is in an interim state. Nevertheless, Exelon used an RRW cutoff of 1.005 in its review of basic events, which corresponds to about a half-percent change in CDF given 100-percent reliability of the SAMA. The NRC staff estimates that this equates to a benefit of approximately $80,000 (after the benefits have been multiplied by a factor of 2.6 to account for external events).

Exelon also provided in the ER tabular listings of the Level 2 PRA basic events for the combined LERF categories and the combined Late Release categories, which in total contribute approximately 95 percent population dose risk and OECR. Exelon also used an RRW cutoff of 1.005 when reviewing these basic events for SAMA candidates. The Level 2 sequences for the intact release category were not included in the review so as to prevent high frequency–low consequence events from biasing the importance listing.

Exelon's review of the Level 1 and Level 2 importance lists resulted in the identification of 26 SAMA candidates.

In its review of these importance lists and the SAMAs identified by Exelon, the NRC staff noted the following (NRC 2014):

- In ER Table F.5-1, for basic event 0VA1SUPP----PNMM "UNIT 1 VA SUPPLY PLENUM MAINTENANCE," the only SAMA identified is SAMA 4, Installation of the "no-leak" RCP seals. The NRC staff suggested a potentially lower cost SAMA to "provide portable ventilation during maintenance activities."

- In ER Table F.5-1 basic events "1AP-142-1---TRMM" and "1AP-142-2---TRMM" appear to result in the unavailability of the same equipment, namely the startup FW pump and the same condensate pumps. The NRC staff determined that this implies that both system auxiliary transformers (SATs) are needed and suggested an alternative SAMA to temporarily align an alternate power source to the FW system while this maintenance is under way.

In response to the RAIs on these issues, Exelon indicated that for basic event 0VA1SUPP----PNMM current plant procedures already direct the alignment of portable fans for CVCS pump room cooling in loss of SX scenarios, which represent 96 percent of the contributors including the 0VA1SUPP----PNMM event. The step to align the portable fans is included in the human failure event (HFE) for establishing alternate lube oil cooling to the CV pumps, which is successful in these scenarios. However, Exelon also stated that the portable fans are not currently credited in the PRA model because there is no basis for assuming they would provide adequate CV pump room cooling (Exelon 2014). Since Exelon already includes providing for portable ventilation in plant procedures and is committed to installing the "no-leak" seals, the NRC staff concludes that this possible alternative SAMA, to provide portable ventilation during maintenance activities, has been adequately explored and is unlikely to be cost-beneficial.

Regarding basic events 1AP-142-1---TRMM and 1AP-142-2---TRMM, Exelon indicated that these events involve the availability of the 142-1 and 142-2 SATs. On a plant trip, the balance of plant loads normally supplied by the unit auxiliary transformers (UATs) are transferred to the associated SATs. If, however, a SAT is out of service for maintenance the transfer is disabled because of the potential for overloading the single available SAT. Because of the load limitations on a single SAT, there are no viable temporary power alignments that could be implemented during SAT maintenance using existing hardware. The loads supplied by the UAT could not be prealigned to the available SAT (load limit issue) and the UATs would be deenergized after a plant trip. The opposite unit's SAT can be tied to the non-Class 1E bus through the Class 1E busses, but nonaccident operation in this configuration is not desirable because of the potential for a single fault to fail a division of power on both units (Exelon 2014). Based on this additional information, the NRC staff concludes that Exelon adequately considered and properly rejected the suggested alternative SAMA.

The Exelon review of the late release categories importance list identified SAMA 24, to provide a reactor vessel cooling system to prevent vessel melt-through, as a means of mitigating basemat melt-through. The NRC staff noted that based on the Byron IPE (ComEd 1994), plant procedures were implemented to direct reactor cavity flooding in core damage scenarios to provide a means of exterior vessel cooling. Based on the IPE implementation of cavity flooding, the NRC staff requested clarification as to why the additional cooling system in SAMA 24 was required to perform this function. Exelon noted that for cases in which core damage occurred, there was a concern that it might not be possible to perform cavity flooding in the time available to prevent vessel failure. Preventing reactor vessel melt-through not only prevents basemat melt-through but also prevents CFEs such as those due to direct containment heating. A fast-acting system might therefore have added benefit. These additional failures were assumed to be mitigated by SAMA 24 in the ER cost-benefit analysis. The NRC staff considers this description of SAMA 24 and the explanation of its potential benefit to be reasonable.

Exelon reviewed the cost-beneficial Phase II SAMAs from prior SAMA analyses for six Westinghouse PWR sites to aid in the identification of additional SAMA candidates. Many of the industry Phase II SAMAs were already represented by other SAMAs in the Byron list, were known not to impact important plant systems or be relevant to the Byron design, or were judged not to have the potential to be close contenders for Byron. As a result, Exelon did not add most of the SAMAs in these prior analyses to the Byron SAMA list. However, Exelon's review resulted in the identification of one additional SAMA candidate, SAMA 26.

The NRC staff noted in an RAI that the NRC staff's evaluation of the Indian Point, Units 2 and 3, SAMA analysis (NRC 2010a) identified 13 potentially cost-beneficial SAMAs for Indian Point Unit 2, whereas the Byron review considered only 7 of the 13 SAMAs (NRC 2014). In response to the RAI, Exelon assessed the additional six Indian Point Unit 2 SAMAs and concluded that each either is not applicable to the Byron design, is implemented at Byron, or is already addressed by a Byron candidate SAMA (Exelon 2014).

In its review of industry cost-beneficial SAMAs, Exelon noted that two Vogtle SAMAs (SAMAs 6 and 16) (NRC 2008) that were originally cost-beneficial were, upon further evaluation of the cost and benefit, judged to not be cost-beneficial at Vogtle. In response to an NRC staff RAI to consider if these SAMAs would be applicable or potentially cost-beneficial at Byron, Exelon determined that the failure being mitigated by Vogtle SAMA 6 (involving adding a bypass line around the cooling tower return valve) is not a significant risk contributor for Byron and the SAMA would not be cost-beneficial. For Vogtle SAMA 16 (involving nonexplicit improvements in ISLOCA procedures), Exelon determined that the intent of this SAMA is already met by existing Byron ISLOCA procedures that are constantly trained on and improved by the plant staff (Exelon 2014). Based on this additional information, the NRC staff concludes that Vogtle SAMAs 6 and 16 have been adequately explored and are unlikely to be cost-beneficial at Byron.

Exelon considered the potential plant improvements described in the IPE in the identification of plant-specific candidate SAMAs for internal events. As described in the ER, while the Byron IPE did not identify any vulnerabilities nor provide a definitive list of enhancements, the report did describe a multisite review of IPE and Accident Management insights. The ER indicated that the IPE discussed two enhancements, both of which have been implemented at Byron (Exelon 2013b).

The NRC staff noted in an RAI that, according to the NRC staff SER for the IPE (NRC 1997b), the transmittal of the modified Byron IPE indicated that a potential vulnerability involving a dual-unit loss of emergency service water (ESW) due to internal flooding had been identified and that a modification was being considered (NRC 2014). In response to the RAI, Exelon indicated that this modification has not been implemented but is included as SAMA 10 (to alter the ductwork between the auxiliary building sump drain room and the SX pump room) in the SAMA analysis (Exelon 2014).

In response to an NRC staff RAI, Exelon indicated that, as part of routine work, PRA groups identify major contributors to plant risk, and, in some cases, the groups have identified specific changes that could reduce risk. As part of the SAMA identification process, the site PRA group was questioned by the applicant's SAMA evaluation team to determine if they have identified any such changes. For Byron, the PRA group did not identify any plant enhancements that were not already identified by the SAMA identification process (Exelon 2014).

In response to an NRC staff RAI that asked Exelon to describe the steps taken to identify SAMAs involving improvements in procedures, training, or available cues for the important human errors, Exelon indicated that the HRA quantifications are reviewed to identify the major contributors to the HEP and to determine if there are any practical means of reducing those contributors. Byron SAMAs 7 and 8 are examples of the results of this process (Exelon 2014).

As discussed above in Section F.2.2.1, the NRC staff noted some differences in PRA results for the Byron site compared to the similar Braidwood site. Exelon indicated that for certain sequences resulting from RCP seal LOCAs, for which the Byron CDF is considerably larger than that for Braidwood, the difference is due to a different normal alignment of the SX crosstie valves at Byron which requires additional operator actions. Exelon indicated that the planned installation of "no-leak RCP seals" would make RCP seal failures noncontributors, and thus a SAMA to change the Byron valve alignment would not be needed. Exelon further indicated that, without the installation of the no-leak RCP seals, changing the Byron normal operation to be consistent with Braidwood would be cost-beneficial. Exelon indicated that it has previously considered changing the Byron valve alignment, but no changes were made because of considerations unrelated to PRA insights (Exelon 2014). Based on Exelon's planned implementation of SAMA 4, install "no-leak" RCP seals, the NRC staff concludes that a SAMA to change the normal position of the SX crosstie valves has been adequately explored and is unlikely to be cost-beneficial.

Based on this information, the NRC staff concludes that the set of SAMAs evaluated in the ER, together with those identified in response to NRC staff RAIs, addresses the major contributors to internal event CDF.

As discussed above, risk insights from the 2009 Bryon fire PRA were used to identify SAMA candidates. Since the fire model was not fully integrated with the most recent Levels 2 and 3 analyses and the model was based on Revision 6C of the internal events PRA rather than the current Revision BB11b1 model, it could not be used directly in the identification of SAMAs. However, the fire contributors that are potentially significant to risk were reviewed to identify potential SAMAs. Exelon considered and evaluated the fire zones with a CDF contribution greater than the IPEEE screening threshold of 1.0×10^{-6} per year for potential SAMAs. These fire zones are listed in Table F-4.

The major fire scenario results for each zone were reviewed and grouped together to help identify target equipment that is common to multiple scenarios in a given fire zone. In response to an NRC staff RAI, Exelon defined major fire scenarios as those contributing 10 percent or more to the fire zone frequency (Exelon 2014). The major scenarios of each of the important fire zones are described and potential SAMAs identified in Section F.5.1.6.1 of the ER. Exelon's review of the major fire scenarios indicated that several of the SAMAs identified to mitigate internal event risks would also mitigate fire-initiated accidents. In addition, Exelon's review of the major fire risk contributors resulted in the identification of three additional SAMA candidates to mitigate fire-initiated accidents.

The NRC staff estimates that the CDF screening value of 1.0×10^{-6} per year equates to a benefit of approximately $110,000 at a 7 percent discount rate. Because $110,000 is essentially equivalent to Exelon's estimate of $100,000 as the cost of a procedure change, the NRC staff considers the CDF screening threshold of 1.0×10^{-6} per year for potential fire-mitigating SAMAs reasonable.

The NRC staff notes that for four fire zones in Unit 1 and for six fire zones in Unit 2 Exelon states, "Because the fire is a 'bounding' scenario, fire scenarios are not developed for all of the specific ignition sources in the fire zone, which limits the potential for fire specific SAMA identification." In an RAI, the NRC staff noted that Fire Zone U2: 11.6-2, the largest contributor to Unit 2 fire CDF, is analyzed using a bounding scenario and asked Exelon to discuss whether or not insights from the analysis of the same or similar fire zone in Unit 1 can be used to identify potential fire-specific SAMAs. Exelon responded that the Unit 1 counterpart of Fire Zone 11.6-2 (Division 22 containment electrical penetrations area) is Fire Zone 11.6-1 (Division 12 containment electrical penetrations area), which was also analyzed as a bounding fire and therefore does not provide any additional insights related to fire sources or propagation (Exelon 2014).

Regarding Fire Zone U1: 11.6c-0 (the auxiliary building laundry room), the NRC asked Exelon to consider a SAMA to move the laundry to another facility if the fire source in the fire zone is due to laundry room operation (NRC 2014). In response to the RAI, Exelon indicated that the laundry equipment has been removed from that room and this room no longer serves that function (Exelon 2014).

In response to an NRC staff RAI that asked Exelon to describe the extent to which new or improved Byron fire procedures mitigate the important fires have been considered in the SAMA analysis, Exelon responded that review of the fire procedures to identify improvements in the fire response is an iterative task that is performed as part of the fire PRA development process and is not within the scope of the SAMA analysis (Exelon 2014). Unlike SAMAs to modify Abnormal Operating Procedures and Emergency Operating Procedures, the identification of fire response enhancement requires coordination with the fire modeling team and procedure writers to ensure the actions are consistent with existing procedures and that the proposed changes are appropriate for the failure modes caused by the fire events (Exelon 2014). The NRC staff concludes that further consideration of new or improved fire procedures is not necessary for the Byron SAMA evaluation, while acknowledging the following:

- The NRC staff cannot conclude that identifying improvements to the fire procedures is beyond the scope of a SAMA analysis since the applicant's CDF screening threshold of 1.0×10^{-6} per year essentially equates to Exelon's estimate of the cost of a procedure change.

- Exelon evaluated all fire zones having a CDF contribution greater than the screening threshold for potential SAMAs,

As discussed in Section F.2.2.2, although the IPEEE did not identify any fundamental vulnerabilities or weaknesses related to external events, several “outliers” were identified from the IPEEE seismic assessment (ComEd 1996). These “outliers” were addressed in the ER and described as “generally items with potential seismically induced interaction issues for which it was difficult to calculate a High Confidence of Low Probability of Failure value” (Exelon 2013b). Exelon described each of the items and their disposition, concluding that no additional SAMAs were needed to address these items. In response to an NRC staff request for clarification of the disposition of these outliers, Exelon provided additional information on each outlier and concluded that each has been dispositioned without the need for additional SAMAs (Exelon 2014).

As stated earlier, the Exelon IPEEE analysis of other external hazards (high winds, tornadoes, external floods, and other external events) did not identify opportunities for improvements for these events.

The NRC staff notes that the Byron external flooding design and capability, seismic design and capability, and the IPEEE seismic “outliers” were assessed in the engineering walkdowns and evaluations required for the response to the Fukushima Near-Term Task Force’s Recommendation 2.3 (Exelon 2012; NRC 2012; Sargent 2012).

An NRC staff RAI questioned Exelon about potentially lower cost alternatives to some of the SAMAs evaluated (NRC 2014), including:

- A SAMA to modify procedures to avoid clearing of RCS cold leg water seals in the event of core damage. In response to the RAI, Exelon explained that this improvement has already been implemented at Byron because the Byron procedures direct an “RCP bump” to inject reactor coolant line water into the reactor vessel only if the SG level is greater than 10 percent which avoids the clearing of the RCS cold leg seal (Exelon 2014).

- An SG PORV gagging device for use after an SGTR and stuck-open SG PORV as an alternate to SAMA 14. In response to the RAI, Exelon explained that the Byron design includes isolation valves with manual handwheels upstream of the SG PORVs, hence the ability to stop flow through a stuck-open PORV exists without the need for the gagging device (Exelon 2014).

- Install “reduced leakage” RCP seals similar to those evaluated for Vogtle SAMA 7 (NRC 2008) as an alternative to the “no-leakage” seals evaluated as Byron SAMA 4. In response to the RAI, Exelon explained that this is not a viable alternative for Byron because (1) Exelon already decided to implement SAMA 4 at Byron, (2) Exelon already made awards for the replacement of the RCP seals, and (3) the cost of engineering and analysis already exceeded the cost given for the Vogtle “reduced leakage” RCP seals (Exelon 2014).

- Installation of additional flood alarms to assist in mitigating important internal flood scenarios. In response to the RAI, Exelon reviewed the internal flooding events and determined that internal flooding alarms already existed or were evaluated in an existing SAMA (SAMA 16), or determined that the flooding sequences are not risk significant (Exelon 2014).

The NRC staff concludes that Exelon used a systematic and comprehensive process for identifying potential plant improvements for Byron, and that the set of potential plant improvements identified by Exelon is reasonably comprehensive and, therefore, acceptable. This search for SAMA candidates by Exelon included reviewing insights from the plant-specific risk studies, and reviewing plant improvements considered in previous SAMA analyses. While explicit treatment of external events other than fire events in the SAMA identification process was limited, the NRC staff determined that the prior implementation of plant modifications identified in the IPEEE and the absence of external event vulnerabilities reasonably justify examining primarily the internal and fire events risk results for this purpose.

The NRC staff also notes that the set of SAMAs submitted by Exelon is not all-inclusive, since additional, possibly even less expensive, design alternatives could be postulated. However, because Exelon's SAMA identification process included reviewing all basic events and fire zones having CDF values greater than or equal to the cost of a procedure change, the NRC staff concludes that the benefits of any additional modifications are unlikely to exceed the benefits of the modifications evaluated and that the alternative improvements would not likely cost less than the least expensive alternatives evaluated, when the subsidiary costs associated with maintenance, procedures, and training are considered.

Exelon's SAMA ID process included reviewing insights from the plant-specific risk studies, and reviewing plant improvements considered in previous SAMA analyses. While explicit treatment of external events in the SAMA identification process was limited, the NRC staff determined that the prior implementation of plant modifications and the absence of external event vulnerabilities reasonably justify examining primarily the internal events risk results for this purpose.

F.4 Risk Reduction Potential of Plant Improvements

Exelon evaluated the risk-reduction potential of the 27 SAMAs retained for the Phase II evaluation in the ER (Exelon 2013b). The SAMA evaluations were generally performed by Exelon in a realistic or conservative fashion that overestimates the benefit of the SAMA. In most cases, the failure likelihood of the added equipment is taken to be optimistically low, thereby overestimating the benefit of the SAMA. In other cases, it was assumed that the SAMA eliminated all of the risk associated with the proposed enhancement. The NRC staff notes that this bounding approach overestimates the benefit and is conservative.

Exelon used model requantification to determine the potential benefits for most of the SAMAs. The CDF, population dose reductions, and offsite economic cost reductions were estimated using the Byron PRA model. The changes made to the model to quantify the impact of each SAMA are described in Section F.6 of the ER for each SAMA. Table F–5 summarizes the assumptions used to estimate the risk reduction for each of the evaluated SAMAs, the estimated risk reduction in terms of percent reduction in CDF, population dose, and offsite economic cost, and the estimated total benefit (present value) of the averted risk. The determination of the benefits for the various SAMAs is further discussed in Section F.6 of this appendix.

The NRC staff reviewed the assumptions used in evaluating the benefit or risk reduction estimate of each of the SAMAs as described in the ER Section F.6. In response to an NRC staff RAI, Exelon clarified that for SAMA 14, automating the refueling water storage tank (RWST) makeup, it is conservatively assumed for both SGTR and non-SGTR sequences that transitioning to recirculation mode and terminating break flow (i.e., controlled cooldown) is required. The human errors associated with both of these scenarios are reduced by a factor of 10 as a result of the additional time available due to this SAMA (Exelon 2014). In response to another NRC staff RAI, Exelon clarified that for SAMA 15, interunit AFW crosstie, no credit is taken for this during dual-unit events since each unit may require use of its own AFW pump (Exelon 2014). The NRC staff considers the assumptions, as clarified, to be reasonable and acceptable for purposes of the SAMA evaluation because they yield conservative results.

For those SAMAs that specifically mitigate fire risk (i.e., SAMAs 27, 28, 30, and 31), a bounding estimate of the SAMA benefits was made. Exelon conservatively assumed that all of the fire risk, or fire CDF, associated with the fire zones affected by the SAMA is eliminated. (Because population dose risk and OECR were not directly calculated, this is noted as "Not Estimated" in Table F–5). Exelon assumed these SAMAs have no additional benefits in internal events. The NRC staff notes that this approach is not necessarily conservative for SAMAs in which the benefit is dominated by the reduction in population dose risk or offsite economic cost risk and not CDF. However, the NRC staff concludes that, since all of the fire mitigating SAMAs were determined by Exelon to be potentially cost-beneficial, further evaluation of these SAMAs is not necessary.

The NRC staff has reviewed Exelon's bases for calculating the risk reduction for the various plant improvements and concludes, with the above clarifications, that the rationale and assumptions for estimating risk reduction are reasonable and generally conservative (i.e., the estimated risk reduction is higher than what would actually be realized). Accordingly, the NRC staff based its estimates of averted risk for the various SAMAs on Exelon's risk reduction estimates.

1 **Table F–5. SAMA Cost/Benefit Screening Analysis for Byron Station**[(a)]

SAMA	Modeling Assumptions	% Risk Reduction			Total Benefit ($)[(b)]		Cost ($)[(b)]
		CDF	Population Dose	OECR	Baseline (Internal + External)	Baseline With Uncertainty	
1 – Install diesel driven SX pump in a new dedicated building[(c)]	Reduce the probability of diesel-driven SX pump failure to 1×10^{-2}.	63	80	89	12.8M	32M	>15M
2 – Replace the positive displacement pump with a self-cooled, auto-start pump	Reduce the probability of RCP seal failure on loss of SX. Seal injection pump failure is 1×10^{-3}; transfer switch is 100% reliable.	66	30	14	4.0M	10.2M	>2.8M
3 – Auto-start of standby SX pump	Reduce the probability of loss of cooling to critical loads on failure of standby SX to start. Auto start failure is 1×10^{-4}.	19	14	9	1.8M	4.5M	>565K
4 – Install "no leak" RCP seals	Reduce the probability of RCP seal for loss of seal cooling. Seal failure probability is reduced by a factor of 1,000.	67	31	15	4.3M	10.6M	>6.5M
5 – Modify the startup feedwater pump to start using the AMSAC SG low-low-low level signal to mitigate AFW failure	Modify FW pump start logic to require failure of both the automated start function and manual operator action. Auto start failure is 1×10^{-4}.	9	21	31	3.9M	9.7M	>328K
7 – Establish flow to the residual heat removal (RHR) HX on RHR pump start	Modify procedures to preclude the need for continuous action statement to protect RHR pumps. Reduce HEP from 7.3×10^{-4} to 1.4×10^{-4}.	2	<1	<1	77K	190K	100K

SAMA	Modeling Assumptions	% Risk Reduction			Total Benefit ($) (b)		Cost ($) (b)
		CDF	Population Dose	OECR	Baseline (Internal + External)	Baseline With Uncertainty	
8 – Install kill switches for the fire protection pumps in the MCR	Reduce the HEP for termination of fire pump flow. Action time is assumed to be 1 minute per pump.	4	3	2	331K	825K	>217K
9 – Install flow restrictors in fire protection pipes	Aux building fire break flow is reduced to 1,000 gpm, and is adequate to meet fire suppression requirements. The increase in available time to terminate flow reduces the flood mitigation factor to 1.2×10^{-4}.	8	6	3	709K	1.8M	>174K
10 – Alter ductwork between the Aux BLDG room and the SX pump room	Completely eliminates the “T1” flooding scenario. Flood mitigation factors for normal SW and SX floods are simplified to HEP for termination of flooding before reaching elevation 364′.	12	12	11	1.7M	4.3M	>660K
11 – Implement diverse mitigation system (DMS)	A portable 480V generator is aligned to support diesel-driven AFW makeup or a portable SG makeup pump. Failure probability for this function is 1×10^{-2}. Cognitive failure to diagnose the need for secondary cooling, and any dependent combinations, are assumed to fail DMS.	88	80	87	13.4M	33M	>7.3M

SAMA	Modeling Assumptions	% Risk Reduction			Total Benefit ($) [b]		Cost ($) [b]
		CDF	Population Dose	OECR	Baseline (Internal + External)	Baseline With Uncertainty	
13 – Alternate AFW cooling with seal protection	**Eliminates SX dependence for motor-driven AFW pump operation. Reduce the probability of RCP seal failure on loss of SX. Seal injection pump failure is 1×10^{-3}; transfer switch is 100% reliable.**	**86**	**80**	**88**	**13.4M**	**33M**	**>3.0M**
14 – Automate RWST makeup	Reduce HEPs for transition to recirculation mode and terminate break flow by a factor of 10. Reduce impacted joint HEPs (JHEPs) to 0 or by a factor of 10.	1	<1	<1	71K	176K	3.8M
15 – Resolve regulatory issues and complete implementation of the interunit AFW crosstie	**The AFW crosstie action execution failure probability is reduced to 2.4×10^{-2}.**	**2**	**2**	**3**	**417K**	**1M**	**0**
16 – Install high flow sensors on the non-SX system	**Completely eliminates all risk associated with SW flood event scenarios.**	**2**	**5**	**6**	**823K**	**2M**	**>496K**
17 – Use AMSAC for alternate low SG level AFW initiation	Eliminates the independent manual AFW initiation HFE in conjunction with all associated JHEPs. The AMSAC logic is 100% reliable.	<1	<1	<1	26K	65K	>490K
18 – Automate refill of the diesel-driven AFW pump fuel oil day tank	Eliminates the independent HFE and all dependent combinations to refill the AFW pump fuel oil day tank. The AMSAC logic is 100% reliable.	<1	<1	<1	78K	194K	>804K

SAMA	Modeling Assumptions	% Risk Reduction			Total Benefit ($) (b)		Cost ($) (b)
		CDF	Population Dose	OECR	Baseline (Internal + External)	Baseline With Uncertainty	
19 – Replace MOVs in the RHR discharge line with valves that can isolate an ISLOCA event	**Completely eliminates all risk from the ISLOCA events occurring in the RHR discharge lines.**	**<1**	**10**	**4**	**637K**	**1.6M**	**900K**
20 – Disallow online RHR maintenance	Eliminates all risk associated with RHR maintenance events.	<1	<1	<1	16K	40k	20M
21 – Install an emergency isolation valve in each of the RHR suction lines	Completely eliminates all risk from the ISLOCA events occurring in the RHR discharge lines.	0	2	1	163K	407K	1.6M
22 – Install the same high flow isolation logic used on Valve_CC685 on Valve_9438	Completely eliminates all risk from the ISLOCA events occurring in the RCP thermal barrier cooling HXs.	0	1	<1	46K	114K	250K
23 – Install a passive hydrogen ignition system	Completely eliminates all containment failures due to hydrogen detonation.	0	<1	<1	40K	99K	760K
24 – Provide a reactor vessel exterior cooling system	Completely eliminates relocation of the core to the containment floor and eliminates all CFEs. Allow scrubbing to maximize averted cost.	0	<1	<1	33K	81K	>1.2M
25 – Install a filtered containment vent	**The filtered vent reduces the consequential dose and offsite economic cost associated with containment overpressure failures by a factor of 10.**	**0**	**72**	**79**	**9.8M**	**24.5M**	**5.7M**

SAMA	Modeling Assumptions	% Risk Reduction			Total Benefit ($) [b]		Cost ($) [b]
		CDF	Population Dose	OECR	Baseline (Internal + External)	Baseline With Uncertainty	
26 – DMS using a dedicated generator, self-cooled charging pump, and a portable AFW pump	**Indefinite AFW makeup capability and an alternate high-pressure injection function capable of providing alternate seal injection to prevent RCP seal LOCAs. The frequency of seal LOCA sequences is reduced by a factor of 100.**	**88**	**80**	**87**	**13.4M**	**33M**	**2.4M**
27 – Protect RHR, SI and CVCS cubicle cooling fan cables in Fire Zone 11.3-0	**Completely eliminates all of the risk associated with Fire Zone 11.3-0.**	[d] **26**	**Not Estimated**		**2.1M**	**5.2M**	**975K**
28 – Install fire barriers around Motor Control Center (MCC) 134X	**Completely eliminates all of the risk associated with Fire Zone 11.6-0.**	[d] **11**	**Not Estimated**		**904K**	**2.3M**	**975K**
29 – Automate swap to recirculation mode	Completely eliminates the contribution from the failure to swap to recirculation mode.	1	<1	<1	45K	110K	>1.2M
30 – Protect AFW cables in the AUX building general area, elevation 383′	**Completely eliminates all of the risk associated with Fire Zone 11.4-0.**	[d] **7**	**Not Estimated**		**571K**	**1.4M**	**975K**
31 – Protect cables for 2AF013A, B, and D in the AUX building general area, elevation 426′	**Completely eliminates all of the risk associated with Fire Zone 11.6-0 (unit 2).**	[d] **20**	**Not Estimated**		**1.6M**	**4M**	**975K**

SAMA	Modeling Assumptions	% Risk Reduction			Total Benefit ($) [b]		Cost ($) [b]
		CDF	Population Dose	OECR	Baseline (Internal + External)	Baseline With Uncertainty	

[a] SAMAs in bold are potentially cost-beneficial.

[b] The estimated benefits and implementation costs were revised in response to NRC staff RAI 3.d, 6.a, and 6.f (Exelon 2014).

[c] The modeling assumptions for SAMA 1 are provided in Exelon 2013a. The estimated risk reduction for SAMA 1 CDF, population dose, and OECR were provided in response to NRC staff RAI 3.d (Exelon 2014).

[d] The risk reduction for fire-mitigating SAMAs was estimated by the NRC staff, utilizing information provided in the ER, as the ratio of the reduction in fire CDF divided by the total fire CDF of 5.4×10^{-5} per year.

Key: AFW = auxiliary feedwater; AMSAC = ATWS mitigating system actuation circuitry; CDF = core damage frequency; CFE = early containment failure; CVCS = chemical and volume control system; DMS = diverse mitigation system; FW = feedwater; gpm = gallons per minute; HEP = human error probability; HFE = human failure event; HX = heat exchanger; ISLOCA = interfacing-systems loss-of-coolant accident; JHEP = joint human error probability; LOCA = loss-of-coolant accident; MCR = main control room; MOV = motor-operated valve; NRC = U.S. Nuclear Regulatory Commission; OECR = offsite economic cost risk; RAI = requests for additional information; RCP = reactor coolant pump; RHR = residual heat removal; RWST = refueling water storage tank; SAMA = severe accident mitigation alternative; SG = steam generator; SW = service water; SX = essential service water

Sources: Exelon 2013a, 2014

F.5 Cost Impacts of Candidate Plant Improvements

In the ER, Exelon estimated the costs of implementing the candidate SAMAs through the development of Byron-specific cost estimates, the use of industry estimates, and, in some cases, combinations of these two sources. It was also noted that Byron-specific implementation costs do include contingency costs for unforeseen difficulties but do not account for any replacement power costs (RPCs) that may be incurred due to consequential shutdown time unless specifically noted. In response to an NRC staff RAI, Exelon stated that a consulting firm was used to develop “order of magnitude” estimates for the cost of SAMA implementation (Exelon 2014). Details such as cost of equipment, demolition, scaffolding, overtime, consumables, freight, engineering, etc. were used to develop the costs. Exelon provided the components of the cost estimates associated with developing supporting procedures, providing lifelong training, and applicable simulator updates.

Exelon also identified in the RAI response that the cost estimates for several SAMAs (SAMAs 2, 3, 4, 5, 8, 9, 10, 11, 13, 16, 17, and 18) were for both Units 1 and 2 rather than for a single unit (Exelon 2014). Revised implementation cost estimates for each of these SAMAs were provided on a per unit basis. The corrected implementation costs were utilized in an updated cost-benefit analysis and are reflected in Table F–5. Detailed cost estimates were not developed for SAMAs that were judged to have implementation costs that far exceeded the estimated benefit.

In response to an NRC staff RAI concerning savings due to sharing of costs between units and between the Byron and Braidwood sites, Exelon clarified that since implementation costs were developed on a “per site” basis, cost sharing between units was accounted for in the updated analysis by dividing the “per-site” costs in half to obtain the “per-unit” costs (Exelon 2014). Cost sharing, however, was not considered between sites. Exelon explained that if cost sharing between sites were possible, engineering costs at the first sister plant are estimated to be generally 75 percent to 80 percent of the original costs if the modifications are identical. However, Exelon indicated that sharing of costs between sites is not appropriate because:

- A SAMA implemented at one site will not necessarily be implemented at the other site.
- While cost sharing between sites could reduce some implementation costs, any reductions in cost would be offset if other costs were also accounted for, such as inflation and RPCs.
- The SAMA designs are conceptual and the cost estimates provided are “order of magnitude” estimates. Changes in the per-site engineering costs of 12 to 13 percent are expected to be within the margin of error.
- Actual installation costs are generally larger than estimated installation costs.
- The impact of accounting for intersite cost-sharing is bounded by the results of the CDF uncertainty analysis, which is discussed in Section F.6.2.

The NRC staff concludes that the amount of cost savings due to sharing of cost between sites is highly uncertain. The NRC staff also believes that the estimated implementation costs could be reduced by up to 25 percent if sharing of costs is accounted for between the Byron and Braidwood sites. However, accounting for a 25 percent reduction in the implementation costs shown in Table F–5 would not result in any additional potentially cost-beneficial SAMAs. Based on this result, the NRC staff considers the RAI issue concerning savings due to sharing of costs between units and between the Byron and Braidwood sites resolved.

Exelon estimated that the minimum cost of making a change to a procedure and for conducting the necessary training on a procedure change to be $100,000. In response to an NRC staff RAI, Exelon stated that although potentially lower cost estimates could be developed for procedure changes, all SAMAs associated with procedure changes were found to be cost-beneficial (Exelon 2014). Since all SAMAs associated with procedure change were found to be potentially cost-beneficial, reducing the cost of a procedure change to less than $100,000 would have no impact on the SAMA analysis results, and, based on this, the NRC staff finds this RAI response acceptable.

For SAMAs 12 and 20, an NRC staff RAI requested that Exelon explain why the implementation cost estimates for these SAMAs assumed an extended outage time rather than assuming maintenance was performed in parallel with other outage activities (NRC 2014). Exelon responded that for SAMA 12, the SAT is the primary source of power to systems supporting spent fuel pool cooling when the fuel is in the spent fuel pool (Exelon 2014). At Byron, SAT work has not been performed during refueling outages as the refueling unit’s SAT is protected during the entire outage. Shutdown risk procedures do not allow for SAT work anytime fuel is in the reactor vessel. The SAT protection could be removed during defueled conditions when the core fuel is in the spent fuel pool. However, the standard template for the defueled window is only 32 hours. The proposed SAT maintenance typically requires approximately 14 days to complete, requiring the outage to be extended. In addition, non-ESF buses are powered by the SAT that is needed during the outage. Reconfiguration of the SAT would hamper the ability to perform other normal outage work. Exelon responded that for SAMA 20, the primary driver is that any work on an RHR train be performed during the defueled window (Exelon 2014). When fuel is in the reactor vessel, it is desirable to have both RHR trains in service. In addition, while pump suction and HX work could be done online, the inability to vent the RH pump discharge requires that this work be performed during an outage. The proposed RHR maintenance typically requires approximately 4 to 5 days to complete, requiring the outage to be extended. Based on this additional information, the NRC staff considers the estimated costs for SAMAs 12 and 20 to be reasonable and acceptable for purposes of the SAMA evaluation.

For certain improvements, the NRC staff compared the cost estimates to estimates developed elsewhere for similar improvements, including estimates developed as part of other licensees’ analyses of SAMAs for operating reactors.

For SAMA 1, Install a dedicated diesel-driven SX pump, the NRC staff noted that the cost estimate from the Limerick SAMA analysis used as the basis for the cost estimate included large HXs and safety-related equipment (PECO 1989). An NRC staff RAI questioned whether non-safety grade equipment could be considered, and that large HXs significantly increase cost but are not needed in SAMA 1 (NRC 2014). In response to the RAI, Exelon reevaluated the cost estimate for SAMA 1 and provided the updated cost, which is included in Table F–5.

Given that Exelon followed the guidance in NEI 05-01 (NEI 2005) and satisfactorily addressed NRC questions regarding cost estimates, the NRC staff concludes that the cost estimates provided by Exelon are sufficient and appropriate for use in the SAMA evaluation.

F.6 Cost-Benefit Comparison

Exelon’s cost-benefit analysis and the NRC staff’s review are described in the following sections.

F.6.1 Exelon's Evaluation

The methodology used by Exelon was based primarily on NRC's guidance for performing cost-benefit analysis, i.e., NUREG/BR–0184, *Regulatory Analysis Technical Evaluation Handbook* (NRC 1997c). The 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 costs ($)
AOSC = present value of averted onsite costs ($)
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 it is not considered cost-beneficial. Exelon's derivation of each of the associated costs is summarized below.

NUREG/BR–0058 has recently been revised to reflect the agency's policy on discount rates. Revision 4 of NUREG/BR–0058 states that two sets of estimates should be developed, one at 3 percent and one at 7 percent (NRC 2004). Exelon provided a base set of results using the 3 percent discount rate and a sensitivity study using the 7 percent discount rate (Exelon 2013b).

Averted Public Exposure Costs

The averted public exposure (APE) costs were calculated using the following formula:

APE = Annual reduction in public exposure (Δ person-rem/year)

× monetary equivalent of unit dose ($2,000 per person-rem)

× present value conversion factor (15.04 based on a 20-year period with a 3-percent discount rate)

As stated in NUREG/BR–0184 (NRC 1997c), it is important to note that the monetary value of the public health risk after discounting does not represent the expected reduction in public health risk due to a single accident. Rather, it is the present value of a stream of potential losses extending over the remaining lifetime (in this case, the renewal period) of the facility. Thus, it reflects the expected annual loss due to a single accident, the possibility that such an accident could occur at any time over the renewal period, and the effect of discounting these potential future losses to present value. For the purposes of initial screening, which assumes elimination of all severe accidents, Exelon calculated an APE of approximately $1,070,000 for the 20-year license renewal period (Exelon 2013b).

Averted Offsite Property Damage Costs

The averted offsite property damage costs (AOC) were calculated using the following formula:

AOC = Annual CDF reduction

× offsite economic costs associated with a severe accident (on a per-event basis)

× present value conversion factor

This term represents the sum of the frequency-weighted offsite economic costs for each release category, as obtained for the Level 3 risk analysis. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, Exelon calculated an

OECR of about \$254,600 based on the Level 3 risk analysis (Exelon 2013b). This results in a discounted value, or AOC, of approximately \$3,830,000 for the 20-year license renewal period.

Averted Occupational Exposure Costs

The averted occupational exposure (AOE) costs were calculated using the following formula:

AOE = Annual CDF reduction

× occupational exposure per core damage event

× monetary equivalent of unit dose

× present value conversion factor

Exelon derived the values for AOE from information provided in Section 5.7.3 of the regulatory analysis handbook (NRC 1997c). Best estimate values provided for immediate occupational dose (3,300 person-rem) and long-term occupational dose (20,000 person-rem over a 10-year cleanup period) were used. The present value of these doses was calculated using the equations provided in the handbook in conjunction with a monetary equivalent of unit dose of \$2,000 per person-rem, a real discount rate of 3 percent, and a time period of 20 years to represent the license renewal period. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, Exelon calculated an AOE of approximately \$24,600 for the 20-year license renewal period (Exelon 2013b).

Averted Onsite Costs

Averted onsite costs (AOSC) include averted cleanup and decontamination costs (ACC) and averted power replacement costs. Repair and refurbishment costs are considered for recoverable accidents only and not for severe accidents. Exelon derived the values for AOSC based on information provided in Section 5.7.6 of NUREG/BR–0184, the regulatory analysis handbook (NRC 1997c).

Exelon divided this cost element into two parts—the onsite cleanup and decontamination cost, also commonly referred to as ACC, and the RPC.

ACCs were calculated using the following formula:

ACC = Annual CDF reduction

× present value of cleanup costs per core damage event

× present value conversion factor

The total cost of cleanup and decontamination subsequent to a severe accident is estimated in NUREG/BR–0184 to be $\$1.5 \times 10^9$ (undiscounted). This value was converted to present costs over a 10-year cleanup period and integrated over the term of the proposed license extension. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, Exelon calculated an ACC of approximately \$774,000 for the 20-year license renewal period.

Long-term RPCs were calculated using the following formula:

RPC = Annual CDF reduction

× present value of replacement power for a single event

× factor to account for remaining service years for which replacement power is required

× reactor power scaling factor

Exelon based its calculations on a Byron net output of 1,185 megawatts electric (MWe) and scaled up from the 910-MWe reference plant in NUREG/BR–0184 (NRC 1997c). Therefore, Exelon applied a power scaling factor of 1185/910 to determine the RPCs. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, Exelon calculated an RPC of approximately $286,000 and an AOSC of approximately $1,060,000 for the 20-year license renewal period.

Using the above equations, Exelon estimated the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at Byron to be about $5,979,393, also referred to as the maximum averted cost-risk (MACR). The internal events MACR is rounded to the next highest thousand ($5,980,000) for SAMA calculations. Use of a multiplier of 2.5 to account for external events increases the value to $14.95M and represents the dollar value associated with completely eliminating all internal and external event severe accident risk for Byron, also referred to as the modified MACR.

Exelon's Results

If the implementation costs for a candidate SAMA exceeded the calculated benefit, the SAMA was considered not to be cost-beneficial. In the baseline analysis contained in the ER (using a 3 percent discount rate), Exelon identified 10 potentially cost-beneficial SAMAs (SAMAs 3, 5, 9, 10, 13, 15, 25, 26, 27, and 31). Based on consideration of uncertainty analysis, Exelon identified an additional eight potentially cost-beneficial SAMAs (SAMAs 2, 7, 8, 11, 16, 19, 28, and 30). In response to NRC staff RAI, Exelon provided the results of revised baseline and uncertainty analyses to account for updated SAMA implementation cost estimates, a revised multiplier of 2.6 to account for external events, and revisions to the uncertainty analysis (Exelon 2014). As a result, Exelon did not identify any additional cost-beneficial SAMAs in the baseline analysis, but did identify two additional potentially cost-beneficial SAMAs when uncertainties were considered (SAMAs 1 and 4).

The potentially cost-beneficial SAMAs for Byron are as follows:

- SAMA 1 – Install Diesel-Driven SX Pump in a new dedicated building
- SAMA 2 – Replace the Positive Displacement Pump with a Self-Cooled, Auto-Start Pump
- SAMA 3 – Auto Start of Standby SX Pump
- SAMA 4 – Install "No Leak" Seals
- SAMA 5 – Modify the Startup Feedwater Pump to Start Using the AMSAC SG Low-Low-Low Level Signal to Mitigate AFW Failure
- SAMA 7 – Establish Flow to the RHR HX on RHR Pump Start
- SAMA 8 – Install Kill Switches for the Fire Protection Pumps in the MCR
- SAMA 9 – Install Flow Restrictors in Fire Protection Pipes
- SAMA 10 – Alter Ductwork Between the Aux BLDG Room and the SX Pump Room
- SAMA 11 – Implement DMS
- SAMA 13 – Alternate AFW Cooling with Seal Protection
- SAMA 15 – Resolve Regulatory Issues and Complete Implementation of the Interunit AFW Crosstie

- SAMA 16 – Install High-Flow Sensors on the non-Essential Service Water System
- SAMA 19 – Replace MOVs in the RHR Discharge Line with Valves that can Isolate an ISLOCA Event
- SAMA 25 – Install a Filtered Containment Vent
- SAMA 26 – DMS Using a Dedicated Generator, Self-Cooled charging Pump, and a Portable AFW Pump
- SAMA 27 – Protect RHR, SI and CVCS Cubicle Cooling Fan Cables in Fire Zone 11.3-0
- SAMA 28 – Install Fire Barriers Around MCC 134X
- SAMA 30 – Protect AFW Cables in the AUX Building General Area, Elevation 383′
- SAMA 31 – Protect Cables for 2AF013A, B, and D in the AUX Building General Area, Elevation 426′

The potentially cost-beneficial SAMAs and Exelon's plans for further evaluation of these SAMAs are discussed in more detail in Section F.6.2.

F.6.2 Review of Exelon's Cost-Benefit Evaluation

The cost-benefit analysis performed by Exelon was based primarily on NUREG/BR–0184 (NRC 1997c) and discount rate guidelines in NUREG/BR–0058 (NRC 2004) and was executed consistent with this guidance.

SAMAs identified primarily on the basis of the internal events analysis could provide benefits in certain external events, in addition to their benefits in internal events. Exelon accounted for the potential risk reduction benefits associated with external events by applying a multiplier to the estimated benefits for internal events. In the analysis reported in the ER, Exelon multiplied the estimated benefits for internal events by a factor of 2.5 incorporating an external events multiplier of 1.5 to account for external events (Exelon 2013b). As discussed above, 10 SAMAs were determined to be potentially cost-beneficial in Exelon's baseline analysis (SAMAs 3, 5, 9, 10, 13, 15, 25, 26, 27, and 31). As discussed in Section F.2.2.2, in response to an NRC staff RAI, Exelon provided a revised baseline evaluation by applying a multiplier of 2.6 [(fire CDF of 5.39×10^{-5} per year + seismic CDF of 1.0×10^{-6} per year + external flooding CDF of 1.0×10^{-6} per year + high winds CDF of 1.0×10^{-6} per year + transportation and nearby facility accident CDF of 1.0×10^{-6} per year) / (internal events CDF of 3.97×10^{-5} per year) + 1] to account for external events (Exelon 2014). The results of this revised evaluation are provided in Table F–5. No additional potentially cost-beneficial SAMAs were identified as a result of this revised evaluation (using a multiplier of 2.6 and a 3-percent discount rate), which incorporated the revised SAMA implementation costs discussed in Section F.5.

Exelon considered the impact that possible increases in benefits from analysis uncertainties would have on the results of the SAMA assessment. In the ER, Exelon presents the results of an uncertainty analysis of the internal events CDF which indicates that the 95th-percentile value is a factor of 2.49 times the point estimate CDF for Byron. Exelon considered whether any additional Phase I SAMAs might be retained for further analysis if the benefits from internal and external events were increased by a factor of 2.49. One additional SAMA (SAMA 20) was identified. Exelon also considered the impact on the Phase II screening if the estimated benefits from internal and external events were increased by a factor of 2.49. The additional Phase I

SAMA, SAMA 20, was included in this sensitivity analysis. As discussed above, eight SAMAs (SAMAs 2, 7, 8, 11, 16, 19, 28, and 30) were determined to be potentially cost-beneficial in Exelon's analysis.

In an RAI, the NRC staff noted that the mean CDF (for PRA model BB011a) was lower than the point estimate and that, usually, the mean CDF is greater than the point estimate because of the correlation of uncertainties (NRC 2014). In response to the RAI, Exelon responded that many of the largest contributors to the Byron PRA results are human probabilities, joint human error probabilities (JHEPs), or flood mitigation events that include operator errors, which are not correlated events. In addition, several contributors with large failure probabilities were assigned lognormal distributions with relatively high error factors. These factors can act to reduce the mean relative to the point estimate. Exelon redid the uncertainty analysis using revised error factors for selected events and determined that the revised 95th-percentile value is a factor of 2.53 times the point estimate CDF for Byron. Exelon considered whether any additional Phase I SAMAs might be retained for further analysis if the benefits from internal and external events were increased by a factor of 2.53 (in addition to the multiplier of 2.6 for external events and revised SAMA implementation costs discussed in Section F.5). One additional SAMA (SAMA 1) was identified. Exelon also considered the impact on the Phase II screening if the estimated benefits from internal and external events were increased by a factor of 2.53 (in addition to the multiplier of 2.6 for external events and revised SAMA implementation costs discussed in Section F.5). Two additional SAMAs (SAMAs 1 and 4) became cost-beneficial as a result of this revised evaluation (using a 3-percent discount rate) (Exelon 2014). The results of this revised evaluation are provided in Table F–5.

Exelon provided the results of additional sensitivity analyses in the ER, including the use of a 7-percent discount rate and variations in MACCS2 input parameters (as discussed in Section F.2.2.4). Exelon determined that these analyses did not identify any additional potentially cost-beneficial SAMAs (Exelon 2013b). In an RAI, the NRC staff requested that Exelon to explain why the MACCS2 sensitivity case for economic rate of return resulted in a change in dose consequence (NRC 2014). In response to the RAI, Exelon provided clarification that the rate of return on property impacts the estimated property that is condemned (or reclaimed). Changes in property reclamation will result in changes in dose consequences to those who occupy the property after it has been reclaimed (Exelon 2014). The NRC staff considers this explanation reasonable.

Exelon stated in the ER (Exelon 2013a) that SAMA 15, Resolve Regulatory Issues and Complete Implementation of the Interunit AFW Crosstie, to improve AFW reliability, was in the final stages of implementation at Byron at the time of the ER submittal and was therefore included as a SAMA rather than being included in the base PRA model. A sensitivity analysis was provided in the ER in which SAMA 15 was incorporated into the base PRA model and the Phase I and II SAMAs reevaluated. This reevaluation did not alter the conclusions of either the Phase I screening analysis or the Phase II cost-benefit analysis.

Exelon also stated in the ER that many of the SAMAs address similar areas of plant risk and that implementation of one SAMA may result in other SAMAs no longer being cost-beneficial. Exelon further noted that SAMA 11, Implement DMS, would mitigate many of the largest contributors to Byron risk, and that it may be fully or partially implemented at Byron for reasons other than the results of the SAMA analysis (specifically, it includes capabilities to address insights from the Fukushima Dai-ichi accident). Exelon reevaluated the cost-beneficial SAMAs assuming both SAMA 15 and SAMA 11 are implemented in an attempt to optimize a reduced set of SAMAs that would address the largest risk contributors. As a result, 10 SAMAs were determined to no longer be cost-beneficial (SAMAs 2, 3, 8, 9, 10, 13, 16, 25, 26, and 27) (Exelon 2013b). In the response to the NRC staff RAI discussed above regarding the revised uncertainty evaluation (applying the factor of 2.53 for uncertainty and the multiplier of 2.6 for external events), Exelon also determined that SAMA 1 would no longer be cost-beneficial if both SAMAs 11 and 15 were implemented (Exelon 2014). SAMA 4 is also effectively implemented in this analysis since installing “no leak” RCP seals is one element of SAMA 11.

Exelon stated in the ER that the 18 SAMAs (SAMAs 2, 3, 5, 7, 8, 9, 10, 11, 13, 15, 16, 19, 25, 26, 27, 28, 30, and 31) determined to be cost-beneficial in the ER baseline and uncertainty evaluations have been submitted to the Byron Plant Health Committee for further implementation consideration (Exelon 2013b). Exelon made no similar commitment for SAMAs 1 and 4, which were determined to be potentially cost-beneficial in response to NRC staff RAIs. In responses to NRC staff RAIs, Exelon stated that installation of SAMA 4 at Byron is planned, that contract awards have been made to install the new RCP seals, and that engineering and analysis work necessary to install the new seals has begun (Exelon 2014). As discussed previously, Exelon stated in the ER that SAMA 11 may be fully or partially implemented at Byron for other purposes, which, if fully implemented along with SAMA 15 (which is currently being implemented), would result in SAMA 1’s no longer being cost-beneficial.

Given that Exelon’s cost benefit evaluations have been reviewed by the NRC staff and that Exelon has satisfactorily addressed NRC staff questions regarding the evaluations, the NRC staff concludes that the cost-benefit evaluations are of sufficient quality to support the SAMA evaluation. Therefore, the NRC staff concludes that, with the exception of the potentially cost-beneficial SAMAs discussed above, the costs of the other SAMAs evaluated would be higher than their associated benefits.

F.7 Conclusions

Exelon initially compiled a list of 30 SAMAs based on a review of the most significant basic events from the plant-specific PRA and insights from the Byron PRA group, insights from the plant-specific IPE and IPEEE, and Phase II SAMAs from license renewal applications for other plants. An initial qualitative screening removed SAMA candidates that: (1) are not applicable to Byron design due to design differences, (2) have already been implemented at Byron or the intent achieved by other means, or (3) have excessive implementation costs. Based on this initial screening, 3 SAMAs were eliminated leaving 27 candidate SAMAs for evaluation. One additional candidate SAMA was also further evaluated after accounting for analysis uncertainties.

For the remaining 28 SAMA candidates, benefit and cost estimates were developed as shown in Table F–5. The cost-benefit analyses in the ER showed that 10 of the SAMA candidates were potentially cost-beneficial in the baseline analysis (SAMAs 3, 5, 9, 10, 13, 15, 25, 26, 27, and 31). Exelon performed additional analyses to evaluate the impact of parameter choices and uncertainties on the results of the SAMA assessment. As a result, eight additional SAMAs were identified as potentially cost-beneficial (SAMAs 2, 7, 8, 11, 16, 19, 28, and 30). Exelon has indicated that all 18 potentially cost-beneficial SAMAs will be submitted to the Byron Plant Health Committee for further implementation consideration.

In response to NRC staff RAI, Exelon reevaluated the 28 SAMA candidates and 1 additional SAMA candidate and, as a result, identified 2 additional potentially cost-beneficial SAMAs (SAMAs 1 and 4). Exelon has plans to implement SAMA 4 and has initiated engineering and procurement activities to do so. Since full implementation of SAMA 11 in conjunction with SAMA 15 (which is currently being implemented) would result in SAMA 1 not being cost-beneficial, the NRC staff concludes that the applicant should consider SAMA 1 for further evaluation, depending on the degree of implementation of SAMA 11.

The NRC staff reviewed the Exelon analysis and concludes that the methods used and the implementation of those methods are sound. The treatment of SAMA benefits and costs support the general conclusion that the SAMA evaluations performed by Exelon are reasonable and sufficient for the license renewal submittal. Although the treatment of SAMAs for external events was somewhat limited, the NRC staff determined that the likelihood of there being additional cost-beneficial enhancements in this area was minimized by utilizing an interim Byron fire PRA to identify SAMA candidates, resolution of suggested plant improvements that were identified as a result of the IPEEE process, and inclusion of a multiplier to account for the external events.

Based on the NRC staff's review of Exelon's SAMA evaluations, including Exelon's response to NRC staff questions regarding the evaluations, the NRC staff concludes that Exelon has adequately identified areas in which risk can be further reduced in a cost-beneficial manner through the implementation of the identified potentially cost-beneficial SAMAs. Given the potential for cost-beneficial risk reduction, the NRC staff concludes that further Exelon evaluation of the candidate SAMAs identified as being potentially cost-beneficial in the Exelon ER is appropriate.

Additionally, the NRC staff evaluated the identified potentially cost-beneficial SAMAs to determine if they are in the scope of license renewal, i.e., they are subject to aging management. This evaluation considers whether the structures, systems, and components (SSCs) associated with these SAMAs: (1) perform their intended function without moving parts or without a change in configuration or properties and (2) that these SSCs are not subject to replacement based on qualified life or specified time period. The NRC staff determined that these SAMAs do not relate to adequately managing the effects of aging during the period of extended operation. Therefore, they need not be implemented as part of license renewal in accordance with Title 10 of the *Code of Federal Regulations*, Part 54, "Requirements for renewal of operating licenses for nuclear power plants."

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10. SUPPLEMENTARY NOTES

11. ABSTRACT (200 words or less)

This supplemental environmental impact statement (SEIS) has been prepared in response to an application submitted by Exelon Generation Company, LLC (Exelon), to renew the operating license for Byron Station, Units 1 and 2 (Byron), for an additional 20 years.

This SEIS includes the preliminary analysis that evaluates the environmental impacts of the proposed action and alternatives to the proposed action. Alternatives considered include: new nuclear generation, coal-integrated gasification combined cycle, natural gas combined cycle (NGCC), combination NGCC, wind, and solar generation, replacement power, and the no action alternative.

The U.S. Nuclear Regulatory Commission (NRC) staff's preliminary recommendation is that the adverse environmental impacts of license renewal for Byron are not so great that preserving the option of license renewal for energy-planning decisionmakers would be unreasonable. This recommendation is based on the following:

- the analysis and findings in NUREG–1437, Volumes 1 and 2, GEIS for License Renewal of Nuclear Plants;
- the Environmental Report submitted by Exelon;
- consultation with Federal, state, local, and tribal government agencies;
- the NRC's environmental review; and
- consideration of public comments received during the scoping process.

12. KEY WORDS/DESCRIPTORS (List words or phrases that will assist researchers in locating the report.)	
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