Applicant's Environmental Report – Operating License Renewal Stage LaSalle County Station

Unit 1
License No. NPF-11

Unit 2
License No. NPF-18

Exelon Generation Company, LLC

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Acronyms and Abbreviations

ΔT	"Delta T" - the change in temperature
ac	acre
ALARA	as low as reasonably achievable
APE	Area of Potential Effect
API	American Petroleum Institute
ARES	alternative retail electric suppliers
BGE	Baltimore Gas and Electric Company
bgs	below ground surface
BOD	biochemical oxygen demand
BP	before present
BPA	Bonneville Power Authority
BTA	Best Technology Available
Btu	British Thermal Units
BWR	boiling water reactor
CAA	Clean Air Act
CAES	compressed air energy storage
CAIR	Clean Air Interstate Rule
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
cfs	cubic feet per second
CH_4	methane
cm	centimeter
CO	carbon monoxide
CO_2	carbon dioxide
COL	Combined Construction and Operation License
ComEd	Commonwealth Edison Company
CPUE	catch per unit effort
CRMP	Cultural Resource Management Plan
CSAPR	Cross-State Air Pollution Rule
CSCS	core standby cooling system
CSP	concentrating solar power
CWA	Clean Water Act
CZMA	Coastal Zone Management Act
DO	dissolved oxygen
DOE	Department of Energy
DSM	demand side management

Acronyms and Abbreviations

EO	Executive Order
EPA	U.S. Environmental Protection Agency
EPACT	Energy Policy Act
ERCOT	Electric Reliability Council of Texas
ESI	Ecological Specialists, Inc.
FESOP	Federally Enforceable State Operating Permit
FR	Federal Register
ft, ft^3	feet, cubic feet
g	gravity
gal	gallon
GEIS	Generic Environmental Impact Statement
GHG	greenhouse gases
gpd	gallons per day
gpm	gallons per minute
GW	gigawatt
ha	hectare
HEPA	high-efficiency particulate air
HFC	hydrofluorocarbon
HRSG	Heat Recovery Steam Generator
HTGR	high temperature gas-cooled reactor
IAC	Illinois Administrative Code
IAS	Illinois Archaeological Survey
IDNR	Illinois Department of Natural Resources
IEMA	Illinois Emergency Management Agency
IEPA	Illinois Environmental Protection Agency
IGCC	Integrated Gasification Combined Cycle
ILCS	Illinois Compiled Statutes
in	inch
INHS	Illinois Natural History Survey
IPA	integrated plant assessment
IPE	individual plant examination
IRSF	Interim Radwaste Storage Facility
ISFSI	Independent Spent Fuel Storage Installation
ISGS	Illinois State Geological Survey
ISMS	Illinois State Museum Society

Acronyms and Abbreviations

ISO	Independent [Transmission] System Operator Independent Standards Organization
kg	kilogram
km; km^2	kilometer; square kilometer
kV	kilovolt
kWh	kilowatt hour
L/day	liters per day
L/min	liters per minute
L/sec	liters per second
lb	pound
LERF	Large Early Release Frequency
LLC	Limited Liability Corporation
LLD	Lower Limit of Detection
LLRW	low-level radioactive waste
LUST	leaking underground storage tank
m	meter
MACCS2	MELCOR Accident Consequence Code System version 2
MATS	Mercury and Air Toxic Standards
mg/L	milligrams per liter
MGD	million gallons per day
mi; mi^2	mile; square mile
MM	Modified Mercalli
mm	millimeter
msl	mean sea level
MW	megawatts
MWd/MTU	megawatt days per metric ton of uranium
MWe	megawatts electric
N_2O	nitrous oxide
NA	not applicable
NAAQS	National Ambient Air Quality Standards
NAWQA	National Water Quality Assessment
NEAC	[DOE] Nuclear Energy Advisory Committee
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NGNP	Next Generation Nuclear Plant

Acronyms and Abbreviations

NH_3	ammonia
NRIS	National Register Information System
NMFS	National Marine Fisheries Service
NMSZ	New Madrid Seismic Zone
NO_2	nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration
NO_x	nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NRC	U.S. Nuclear Regulatory Commission
NRCS	Natural Resource Conservation Service
NREL	National Renewable Energy Laboratory
NRHP	National Register of Historic Places
NSPS	New source performance standards
NWI	National Wetlands Inventory
OTEC	ocean thermal energy conversion
PCB	polychlorinated byphenols
pCi/L	picocuries/liter; a picoCurie is one trillionth of a Curie; a Curie is the amount of a radioactive isotope that decays at a rate of 3.7×10^{10} disintegrations per second
PECO	PECO Energy Company
PFC	perfluorinated compounds
PHS	pumped hydro storage
PIAT	payment in addition to taxes
PIMW	potentially infectious medical waste
PJM Interconnection	Central Atlantic and Midwestern regional electric distribution network
PM_{10}	particulate matter with aerodynamic diameters of 10 microns or less
$PM_{2.5}$	particulate matter with aerodynamic diameters of 2.5 microns or less
PRA	probabilistic risk assessment
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
PV	photovoltaic
PWR	pressurized water reactor
REMP	Radiological Environmental Monitoring Program
RGPP	Radiological Groundwater Protection Plan
ROI	Region of Interest

Acronyms and Abbreviations

ROW	right-of-way
RPS	Renewable Portfolio Standards
SAMA	severe accident mitigation alternatives
SCR	selective catalytic reduction
SF_6	sulfur hexafluoride
SHPO	State Historic Preservation Officer
SIP	State Implementation Plan
SMITTR	surveillance, monitoring, inspection, testing, trending and recordkeeping
SO_2	sulfur dioxide
SO_x	sulfur oxides (compounds containing sulfur and oxygen such as SO_2 and SO_3).
SSE	safe shutdown earthquake
SWPPP	Storm Water Pollution Prevention Plan
TEDE	total effective dose equivalent
tpy	tons per year
TSP	total suspended particulates
UFSAR	Updated Final Safety Analysis Report
$\mu g/L$	microgram per liter
USC	United States Code
USCB	U.S. Census Bureau
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
VOC	volatile organic compound
WCD	Waste Confidence Decision
WRDA	Water Resources Development Act
yd	yard
yr	year

Chapter 1

Introduction

1.1 Purpose of and Need for Action

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants in accordance with the Atomic Energy Act of 1954, as amended, and NRC implementing regulations. Exelon Generation Company, LLC (Exelon Generation) operates the LaSalle County Station, Units 1 and 2 pursuant to NRC Operating Licenses NPF-11 (Unit 1) and NPF-18 (Unit 2). The license for Unit 1 will expire on April 17, 2022. The license for Unit 2 will expire on December 16, 2023. LaSalle County Station is located in rural LaSalle County in northern Illinois.

Exelon Generation has prepared this Environmental Report in conjunction with its application to NRC to renew the LaSalle County Station operating licenses, as provided by the following NRC regulations:

> Title 10, Energy, Code of Federal Regulations (CFR), Part 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants, Section 54.23, Contents of Application - Environmental Information (10 CFR 54.23) and
>
> Title 10, Energy, CFR, Part 51, Environmental Protection Requirements for Domestic Licensing and Related Regulatory Functions, Section 51.53, Post-construction Environmental Reports, Subsection 51.53(c), Operating License Renewal Stage [10 CFR 51.53(c)] (78 Federal Register [FR] June 20, 2013) (NRC 2013a).

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

> "The purpose and need for the proposed action (issuance of a renewed license) is to provide an option that allows for baseload 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 decision-makers, such as State, utility, and, where authorized, Federal agencies (other than the NRC). Unless there are findings in the safety review required by the Atomic Energy Act or the NEPA [National Environmental Policy Act] environmental review that would lead the NRC to reject a license renewal application, the NRC does not have a role in the energy-planning decisions of whether a particular nuclear power plant should continue to operate." (NRC 2013b)

The renewed operating licenses would allow an additional 20 years of operation for the LaSalle County Station units beyond their current licensed operating periods. The renewed license for LaSalle County Station Unit 1 would expire on April 17, 2042, and the renewed license for LaSalle County Station Unit 2 would expire on December 16, 2043.

1.2 Environmental Report Scope and Methodology

NRC regulations for domestic licensing of nuclear power plants require reviews of environmental impacts from renewing an operating license. NRC regulation 10 CFR 51.53(c) requires that an applicant for license renewal submit with its application a separate document entitled Applicant's Environmental Report - Operating License Renewal Stage. In determining what information to include in the LaSalle County Station license renewal Applicant's Environmental Report, Exelon Generation has relied on NRC regulations and the following supporting documents that provide additional insight into the regulatory requirements:

- Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS), Revision 1 (NRC 2013b), and referenced information specific to transportation (NRC 1999a)
- NRC supplemental information in the Federal Register (NRC 1999a, NRC 1999b, NRC 2013a)
- Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses (NRC 1996a)
- Regulatory Guide 4.2, Supplement 1, Revision 1 Preparation of Environmental Reports for Nuclear Power Plant License Renewal Applications (NRC 2013c)

Exelon Generation has prepared Table 1.2-1 to verify conformance with regulatory requirements. Table 1.2-1 indicates the sections in the LaSalle County Station License Renewal Environmental Report that respond to each requirement of 10 CFR 51.53(c). In addition, each responsive section is prefaced by a boxed quote of the associated regulatory language and applicable supporting document language.

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

Regulatory Requirement	Responsive Environmental Report Section(s)	
10 CFR 51.53(c)(1)		Entire Document
10 CFR 51.53(c)(2), Sentences 1 and 2	2.0	Proposed Action and Alternatives
10 CFR 51.53(c)(2), Sentence 3	7.1	Alternatives to the Proposed Action
	8.0	Comparison of Environmental Impact of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(1)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	6.3	Unavoidable Adverse Impacts
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	2.6	Alternatives to the Proposed Action
	7.0	Alternatives to the Proposed Action
	8.0	Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(4)	6.5	Short-Term Use Versus Long-Term Productivity of the Environment
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(5)	6.4	Irreversible and Irretrievable Resource Commitments
10 CFR 51.53(c)(2) and 10 CFR 51.45(c)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
	6.2	Mitigation
	7.0	Alternatives to the Proposed Action
	8.0	Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(d)	9.0	Status of Compliance
10 CFR 51.53(c)(2) and 10 CFR 51.45(e)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(3)(ii)(A)	4.5.1	Surface Water Use Conflicts (Plants with Cooling Ponds or Cooling Towers Using Make-up Water from a River)
	4.5.2.2	Groundwater Use Conflicts (Plants with Closed-Cycle Cooling Systems that Withdraw Make-up Water from a River)
	4.6.2.2	Water Use Conflicts with Terrestrial Resources (Plants with Cooling Ponds or Cooling Towers Using Make-up Water from a River)
	4.6.3.3	Water Use Conflicts with Aquatic Resources (Plants with Cooling Ponds or Cooling Towers Using Make-up Water from a River)
10 CFR 51.53(c)(3)(ii)(B)	4.6.3.1	Impingement and Entrainment of Aquatic Organisms (Plants with Once-through Cooling Systems or Cooling Ponds)
	4.6.3.2	Thermal Impacts on Aquatic Organisms (Plants with Once-through Cooling Systems or Cooling Ponds)

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

Regulatory Requirement	Responsive Environmental Report Section(s)	
10 CFR 51.53(c)(3)(ii)(C)	4.5.2.1	Groundwater Use Conflicts (Plants that Withdraw >100 gpm)
10 CFR 51.53(c)(3)(ii)(D)	4.5.2.3	Groundwater Quality Degradation (Plants with Cooling Ponds at Inland Sites)
10 CFR 51.53(c)(3)(ii)(E)	4.6.2	Effects on Terrestrial Resources (Non-cooling System Impacts)
	4.6.4.1	Threatened, Endangered, and Protected Species and Essential Fish Habitat
10 CFR 51.53(c)(3)(ii)(G)	4.9.1	Microbiological Hazards to the Public
10 CFR 51.53(c)(3)(ii)(H)	4.9.2	Electric Shock Hazards
10 CFR 51.53(c)(3)(ii)(K)	4.7	Historic and Cultural Resources
10 CFR 51.53(c)(3)(ii)(L)	4.15	Severe Accidents Mitigation Alternatives
10 CFR 51.53(c)(3)(ii)(N)	3.11	Environmental Justice
	4.10.1	Minority and Low Income Populations
10 CFR 51.53(c)(3)(ii)(O)	4.12	Cumulative Impacts
10 CFR 51.53(c)(3)(ii)(P)	4.5.2	Radionuclides Released to Groundwater
10 CFR 51.53(c)(3)(iii)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
	6.2	Mitigation
10 CFR 51.53(c)(3)(iv)	5.0	Assessment of New and Significant Information

1.3 LaSalle County Station Licensee and Ownership

LaSalle County Station is owned and operated by Exelon Generation Company, LLC (Exelon Generation), the applicant and licensee. The LaSalle County Station is connected to the regional electricity grid at the Station switchyard.

Exelon Generation Company, LLC is a Delaware limited liability company which is wholly owned by Exelon Ventures Company, a Delaware limited liability company, which in turn is wholly owned by Exelon Corporation, a corporation formed under the laws of the Commonwealth of Pennsylvania. Exelon Generation Company, LLC, is the licensed operator of LaSalle County Station, Units 1 and 2.

Chapter 2

Proposed Action and Description of Alternatives

LaSalle County Station Environmental Report

2.1 The Proposed Action

NRC

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

Exelon Generation proposes that NRC renew the operating licenses for LaSalle County Station (LSCS) Units 1 and 2 for an additional 20 years beyond the current licenses' expiration dates of April 17, 2022 for Unit 1 and December 16, 2023 for Unit 2. Renewal of the operating licenses would give Exelon Generation and the State of Illinois the option of relying on LSCS to meet future baseload power generating needs during the period of extended operation.

In addition to continuing operation and maintenance activities, nuclear power plants may conduct refurbishment activities to support extended operation during the license renewal term. Refurbishment is not anticipated for LSCS. The relationship of refurbishment to license renewal is described in Section 2.3.

During the license renewal term, changes to surveillance, as well as online monitoring, inspections, testing, trending, and recordkeeping (SMITTR) could be undertaken as a result of the 10 CFR Part 54 aging management review. Potential SMITTR activities are described in Section 2.4.

No other plant upgrades to support extended operations and that could directly affect the environment or plant effluents are planned.

2.2 General Plant Information

NRC

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

LSCS is a two-unit, nuclear-powered, steam electric generating facility. Both units began commercial operation in 1984 (Exelon Corporation 2013a). The nuclear reactor for each unit is a General Electric boiling water reactor (BWR/5). The annual mean net electrical power capacity rating for the Station is 2,327 megawatts electric (MWe) (Exelon Corporation 2013a). Figure 2.2-1 depicts the site property boundary.

The LSCS power generation complex includes several contiguous buildings (Figure 2.2-2): two reactor buildings, an auxiliary building (housing the control room), and the turbine building. Other facilities such as the radwaste building, service building, lake screen house, sewage treatment facilities, training facilities, switchyard, and the independent spent fuel storage installation (ISFSI) are also located in the power generation complex.

Condenser cooling water and plant service water are provided by an approximately 833 hectare (ha) (2,058-acre [ac]) (NRC 1978) diked cooling pond adjacent to the plant. The ultimate heat sink (UHS), also known as the "core standby cooling system pond," is an excavated 34-ha (83-ac) area within the cooling pond immediately in front of the intake canal (Figure 2.2-1). The ultimate heat sink can retain approximately 56.7 ha-m (460 ac-ft) of water, sufficient for 30 days of cooling without make-up (Exelon Nuclear 2012a) following safe Station shutdown from normal operating or accident conditions. A small screen house on the Illinois River provides makeup water to the cooling pond. Downstream of the intake structure is a discharge structure where blowdown from the cooling pond is returned to the river.

Chapter 2 subsections provide information on the reactor and containment systems; fuel enrichment, burnup and storage; the cooling and auxiliary water systems; Station emission sources; the meteorological monitoring program; the power transmission system; radioactive waste management systems; and non-radioactive waste management systems. Additional information about LSCS is available in the final environmental statement for operation of the plant (NRC 1978), the Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 2013b), and the Updated Final Safety Analysis Report (UFSAR) (Exelon Nuclear 2012a).

2.2.1 Reactor and Containment Systems

Both Units 1 and 2 are General Electric (GE) BWR/5's with Mark II containments (Exelon Nuclear 2012a). In this design, the reactor vessel houses the reactor core containing the nuclear fuel, the control rods, steam separators, steam dryers, and other components.

Preheated water, recycled from the condenser, enters the reactor vessel and flows through the reactor core, where the heat from fission reactions in the fuel causes it to boil. Steam mixed with water rises to the top of the core. Because the steam is formed within the reactor core, it contains radioactive impurities in the form of gasses, termed offgasses. The steam-water mixture leaves the top of the core and enters steam separators and then steam dryers, where water droplets are removed before the steam enters the steam line to the main turbine, causing it to turn the attached electrical generator. Upon exiting the turbine, the steam is sent to the condenser where it is condensed back into water as a result of heat removal by cooling water circulating in pipes that pass through the condenser shell. The condensate collects in the condenser hotwell at the bottom of the condenser shell and is pumped through feedwater heaters and back to the reactor vessel. Offgasses collect in the top of the condenser shell from which they are continuously removed by an air ejector to the offgas treatment system before being discharged to the environment via the Station vent stack.

The primary containment is comprised of a dry well and a wet well. The dry well is a concrete and steel structure, which houses the reactor vessel, the reactor coolant recirculation loops, and other principal connections of the reactor coolant loops. The wet well is a cylindrical chamber constructed of stainless steel-lined concrete with a diameter of nearly 27 meters (m) (90 feet [ft]). It contains water used to suppress steam discharged from the reactor vessel during transients[1] and accidents and to supply emergency core cooling systems.

The reactor building completely surrounds the primary containment and functions as a secondary containment. The reactor building also houses refueling and reactor servicing equipment, new and spent fuel storage facilities, and other reactor safety and auxiliary systems.

The containment systems and their engineered safeguards are designed to ensure that offsite doses resulting from postulated accidents are well below the guidelines in 10 CFR Part 100.

[1] A transient is a change in the reactor cooling system's temperature, pressure or both, as a result of a change in the reactor power output.

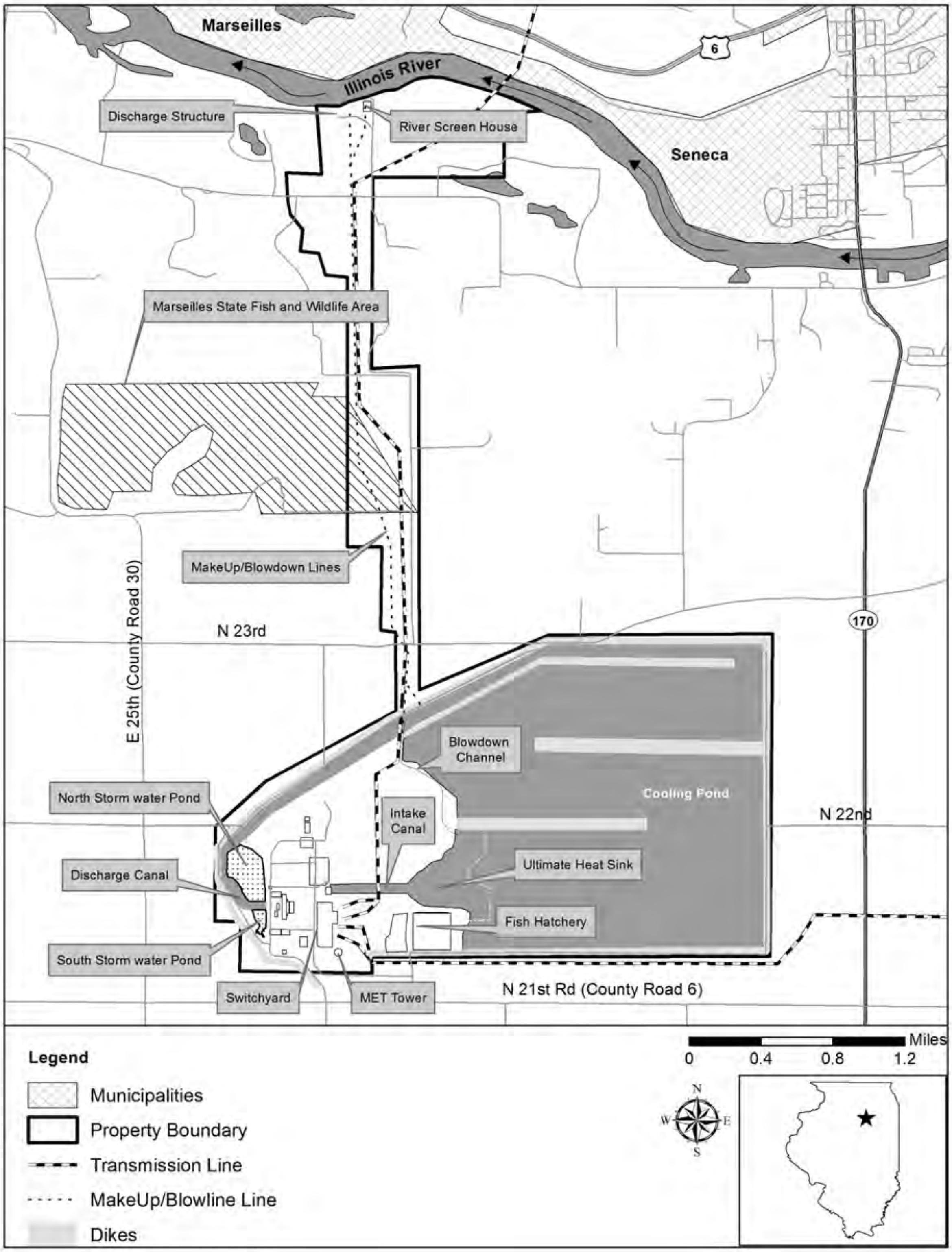

Figure 2.2-1 LSCS Site Layout

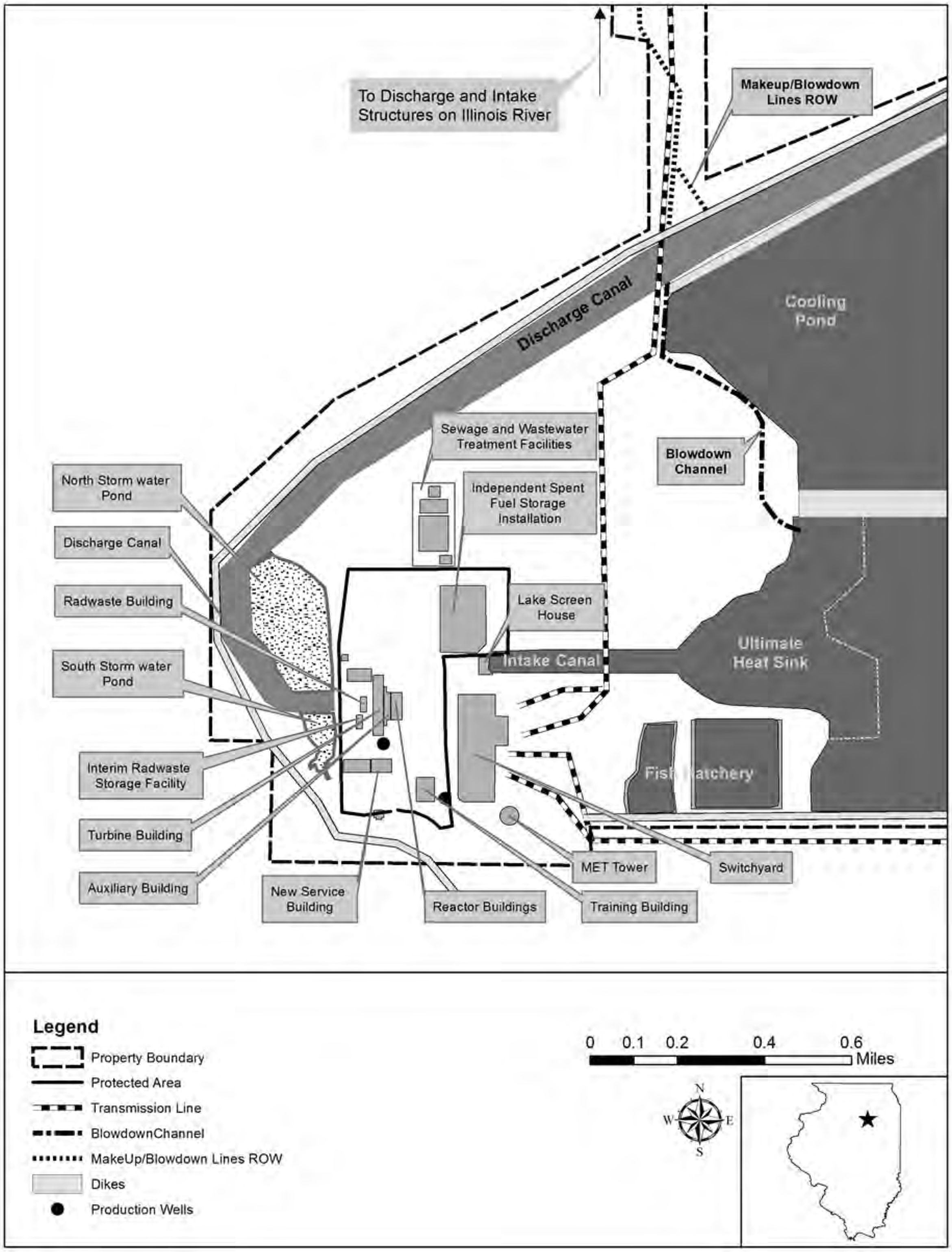

Figure 2.2-2 LSCS Plant Layout

2.2.2 Fuel Enrichment, Burn-Up, and Storage

Both LSCS units are operating using low-enriched, uranium dioxide fuel with enrichment not exceeding a nominal 5.0 percent by weight of uranium-235 and have been historically operated within a maximum analyzed fuel burn-up rate of 62,000 megawatt-days per metric ton uranium (Exelon Nuclear 2012a). However, during some future fuel cycles, the peak fuel burnup is projected to exceed 62,000 MWd/MTU in some part-length fuel rods. Section 4.13 describes the assessment Exelon Generation did of the implications of this new information to the environmental impacts associated with transporting radioactive materials to and from nuclear reactors, as reported in Table S-4 of 10 CFR 51.52. Section 5.2 explains why, although the information is new, it is not significant. The uranium dioxide fuel is in the form of high-density ceramic pellets stacked in a Zircaloy cladding tube). LSCS operates a spent fuel pool and an independent spent fuel storage installation (ISFSI). The Unit 1 spent fuel storage pool is designed for approximately 520 percent of the full core load or 3,986 fuel assemblies. For Unit 2, the spent fuel storage pool is designed for approximately 530 percent of the full core load or 4,073 fuel assemblies. (Exelon Nuclear 2012a)

Dry casks in the ISFSI provide onsite storage of spent nuclear fuel for both Units 1 and 2. The ISFSI is in the northeast corner of the Protected Area. The ISFSI complies with the General License issued under 10 CFR Part 72, Subpart K (General License for Storage of Spent Fuel at Power Reactor Sites) and the conditions contained in the Certificate of Compliance for the cask system. Spent fuel transfers to the ISFSI began in May, 2010.

The GEIS (NRC 2013b) noted that radiological impacts from onsite storage of spent nuclear fuel to human health during the term of license renewal would be well within regulatory limits, and hence, would be SMALL. Nonradiological impacts from spent fuel storage during the license renewal term were also identified as SMALL. In accordance with this determination, the 2013 GEIS concludes that within the context of license renewal, the NRC regulatory requirements for spent nuclear fuel provide adequate protection of plant workers, the public, and the environment. Notwithstanding, the 2013 GEIS states that the NRC will not make any decision or recommendation regarding license renewal on the basis of this information for the reasons discussed below.

In 2010, the Commission updated and continued the provisions in 10 CFR 51.23 (referred to as the Waste Confidence Decision Update and Temporary Storage Rule, or WCD Update and Rule) based on experience in the interim storage of spent nuclear fuel and the increased uncertainty in siting and constructing a permanent geologic repository for the disposal of spent nuclear fuel (75 FR 81031; December 23, 2010). On June 8, 2012, the D.C. Circuit Court of Appeals vacated and remanded the WCD Update and Rule (New York v. NRC, 681 F.3d 471 (D.C. Cir. 2012)). In response, the NRC Commissioners suspended issuance of licenses that would depend on the WCD Update and Rule (NRC 2012a). Because the Commissioners considered responding to the D.C. Circuit Court's concerns to be a generic issue, they further directed the NRC staff to conduct a rulemaking (NRC 2012b). The updated final Continued Storage Rule and the Notice of Availability for the supporting Generic EIS for Continued Storage of Spent Nuclear Fuel, which provides the NEPA analyses of human health and environmental impacts of continued storage of spent nuclear fuel beyond the licensed life of a reactor that is needed to support renewal of the LSCS operating licenses, were published in the *Federal Register* on September 19, 2014 (79 FR 56238 -56264).

2.2.3 Cooling and Auxiliary Water Systems

Condenser cooling is the principal water use at LSCS. Other water systems are the Station service water system, the core standby cooling system (CSCS) equipment cooling water system, the potable and sanitary water system, and the storm water management system. Each system is described below.

Circulating Water System

The circulating water system takes water from the 833 hectare (ha) (2,058-acre [ac] (NRC 1978) man-made diked cooling pond (Figure 2.2-1) to provide the condenser with a continuous supply of cooling water. After cooling the steam back to water in the condenser, as described in Section 2.2.1, the heated circulating water is discharged back to the cooling pond. Water flow in the pond is directed by a series of dikes arranged to prolong the cooling time in the pond, which ensures that the coolest water is available at the lake screen house. At the lake screen house, pond water is returned to the condensers after being drawn through bar grills, and 3/8" mesh traveling screens and directed to six circulating water pumps (three for each unit). At 100 percent clean, the screens are designed for a through-screen flow velocity of approximately 0.7 m/s (2.2 fps). For each unit, two circulating water pumps are normally in service. Each pump supplies flow to the unit's condenser at an estimated 2.3×10^6 liters/minute (L/min) (616,500 gallons per minute [gpm]). Debris removed from the traveling screens by a screen backwash system and from the bar grills by trash rakes is collected in a trash basket and disposed in an offsite permitted landfill. The lake screen house traveling screens have no fish return system. Biocides and scale inhibitors are injected into the circulating water piping at the lake screen house (Exelon Nuclear 2012a).

The cooling pond was constructed at the time of LSCS construction to serve as the heat sink for dissipation to the atmosphere of waste heat from the LSCS (ComEd 1977). It was created by constructing three dikes totaling 11,565 m (37,942 ft) in length (Exelon Nuclear 2012a). The fourth side of the pond is a natural levee. Water was pumped into the terrestrial, diked area through a pipeline from the Illinois River, which is located approximately 5.6 kilometers (km) (3.5 miles [mi]) north of the cooling pond (Figure 2.2-1) and which now provides makeup to maintain water level in the cooling pond. The cooling pond dissipates heat from the condenser cooling water such that blowdown to the Illinois River meets temperature limitations and mixing zone requirements, as specified in the Illinois thermal water quality standards (35 IAC 302) (ComEd 1977). NPDES Permit No. IL0048151 authorizes releases to the cooling pond of other wastewater streams in addition to condenser cooling water, and the cooling pond blowdown is subject to wastewater discharge limitations specified in the NPDES permit. Accordingly, the cooling pond is defined as a wastewater "treatment works" (35 IAC 301.415), and as such it is excepted from the definition of "waters of the state" (35 IAC 301.440) as well as the definition of "waters of the United States" under the federal Clean Water Act (40 CFR 230.3(s)). As a result, the water inventory within the cooling pond is not subject to state water quality standards.

The cooling pond has a capacity of 3,910 ha-m (31,706 ac-ft). Water in the cooling pond is directed by three baffle dikes to prolong the cooling time, ensuring that the coolest water is available at the lake screen house. The minimum operating level of the pond is 213 m (697.75 ft) (Exelon Nuclear 2012a).

Exelon Generation has leased portions of the cooling pond to the Illinois Department of Natural Resources (IDNR) for public access fishing, and some Exelon Generation property adjacent to the pond is leased to the IDNR for a state fish hatchery. IDNR manages the cooling pond fishery resource pursuant to the provisions of the lease, however Exelon Generation retains the right of access at all times, and the right, with reasonable notice to restrict or prohibit public access as necessary for maintenance or operational purposes. Also, if the Generating Station Emergency Plan is activated, Exelon Generation has sole authority under the lease to control access and exclude all persons from the cooling pond without prior notices. Exelon Generation also retains sole authority to exclude any and all persons from the fish hatchery property. The cooling pond lease provides that IDNR will manage the cooling pond to avoid interference with LSCS operations and Exelon Generation will minimize adverse consequences to the cooling pond from LSCS operations.

Makeup water to the cooling pond to replace losses due to evaporation, blowdown, and seepage is withdrawn from the Illinois River at the river screen house using a combination of three makeup pumps. Makeup water requirements can be met by operating one or two pumps for normal operations with one pump for backup. Each pump's rated capacity is 114,000 L/min (30,000 gpm) (Exelon Nuclear 2012a). Maximum water withdrawal from the Illinois River is, therefore, approximately 340,000 L/min (90,000 gpm). Normal water withdrawal, with two pumps operating, is up to 227,125 L/min (60,000 gpm).

The makeup water intake system consists of an intake flume channeled into the bottom of the Illinois River and extending approximately 15 m (50 ft) out from the shoreline. Recessed 7 m (24 ft) from the shoreline is a 22-m (72-ft) wide funnel inlet. At the mouth of the inlet, a floating log boom diverts floating debris and, in the river screen house forebay, a permanent floating oil boom prevents any oil spill from entering to the river. The inlet leads to two adjacent bar grills and traveling screens, with 3/8 inch screen openings, in the river screen house. Debris removed from the traveling screens by a screen backwash system and from the bar grills by trash rakes is collected in a trash basket and disposed in an offsite permitted landfill. The river screen house has no fish return system. The river screen house is approximately 5.6km (3.5 mi) from the cooling pond.

Discharging from a cooling pond keeps dissolved solids from building up in the pond. At LSCS, blowdown flows from the cooling pond to permitted Outfall 001 via an open canal that flows into a 170-centimeter (cm) (66-inch [in]) diameter pipeline designed for gravity flow back to the Illinois River. The blowdown pipeline traverses the same right-of-way as the intake pipeline. The blowdown discharge structure is downstream of the intake structure. The maximum blowdown flow rate is approximately 340,000 L/min (90,000 gpm), but a motor-operated control valve located near the discharge point in the blowdown line adjusts the flow rate to limit normal blowdown flow to 220,000 L/min (58,000 gpm) or less with a target annual average of 114,000 L/min (30,000 gpm). In addition to cooling pond blowdown, the blowdown pipeline receives other wastewater streams as authorized by the LSCS NPDES Permit No. IL0048151.

The makeup and blowdown water pipelines are constructed of pre-stressed cylindrical concrete pipe ranging in size from 137 cm (54 in) to 170 cm (66 in) in diameter and are buried parallel to one another in a common right-of-way, except for the slight separation near the river screen house. The buried pipes follow the lay of the land, which is relatively flat near the cooling pond and the river, but consists of rolling hills that create multiple low spots and many elevation changes between the two flat regions. The makeup pipe is equipped with air and vacuum relief valves at various locations along its length to accommodate the high pressure surges and vacuum conditions caused by the elevation changes. Because the blowdown line is gravity fed, it sees fewer pressure transients than the makeup line. Even so, pressure surges do occur in the blowdown pipe as a result of events such as value adjustments described above that are needed to maintain the normal blowdown flow rate. If flow rate changes too fast, the sudden valve adjustment can cause a water hammer in the blowdown line. Accordingly, like the makeup pipeline, the blowdown pipeline is equipped with relief valves.

Through the years, the LSCS makeup and blowdown pipelines, which serve no safety-related function, have experienced multiple breaks which are attributed to pressure surges in the pipelines that put stress on the piping resulting in breaks. Three times more makeup pipe breaks have occurred than blowdown pipe breaks.

Releases from blowdown pipe breaks are reported in accordance with Standard Condition 12 (Reporting Requirements) in the LSCS NPDES Permit IL0048151. Potential environmental effects from both makeup and blowdown pipe breaks include localized flooding and erosion in the vicinity of the break. Also, minor releases of radioactivity are possible from blowdown line breaks Although the potential for this is low because LSCS maintains a goal of zero liquid radioactive release to the cooling pond (see Section 2.2.7.1).

Exelon Generation is implementing the following actions to reduce the frequency of breaks and impacts when breaks occur:

- A long-term plan to replace existing relief valves in both pipelines with new valves that allow controlled venting, which can mitigate some effects of pressure surges.
- The frequency of makeup line pressure transients has been reduced by raising the traveling screen differential pressure setpoint and by installing traveling screen digital recorders. The digital recorders provide data on travelling screen parameters that are monitored by operators to identify abnormal trends that suggest when screen maintenance would be appropriate to prevent makeup pump trips.
- Parts are kept on hand for replacement of one section of pipe.
- A plan is maintained for rapid repairs to the pipeline.
- If deemed necessary, backfill is applied in critically eroded areas.
- Procedures dictate conservative control of the blowdown valve and the makeup pumps.
- In accordance with applicable plant procedures, operator field rounds have been modified to include semi-annual verification of pipeline integrity as well as pipeline integrity verification after filling the makeup and/or blowdown pipes.

Service Water System and CSCS Equipment Cooling Water System

Two auxiliary water systems at LSCS use water from the cooling pond: the service water system supplies non-safety related systems and the core standby cooling system (CSCS) equipment cooling water system supplies safety-related equipment necessary for safe shutdown of the reactors.

The service water system provides cooling water for various non-safety-related Station auxiliary systems and components. The service water system also provides (1) water for filling the fire protection system and to serve as a backup fire water supply, (2) water for the traveling screen wash, and (3) water for the radwaste system. The service water system has five main pumps (60,570 L/min [16,000 gpm] each) and two jockey pumps (18,930 L/min [5,000 gpm] each) in the lake screen house. Normally, four main service water pumps are operated, two for each unit, with the fifth pump available as a backup for either unit. The service water jockey pumps would provide minimum flow requirements during a loss of offsite power. These jockey pumps can be powered by an emergency diesel generator. During shutdown and startup of either unit, the combination of main and jockey pumps can be adjusted to meet service water system cooling requirements. The Station service water pumps are in the lake screen house, and service water discharges to the cooling pond.

The CSCS equipment cooling water system is equivalent in purpose to the essential service water systems at other nuclear stations. It withdraws cooling pond water from the LSCS ultimate heat sink (UHS) for the purpose of cooling safety-related equipment necessary for safe shutdown of the reactors. The LSCS UHS, also known as the core standby cooling system pond, is an 83-acre submerged area located directly in front of the lake screen house (Figure 2.2-1) that has been excavated to a depth designed to hold approximately 56.7 ha-m (460 ac-ft) of water, which is enough water to support safe Station shutdown from normal operating or accident conditions and subsequent cool-down without adding makeup water for 30 days. The CSCS equipment cooling water system circulates cooling water from the UHS to safety-related equipment. This system draws water from the service water tunnel in the basement of the lake screen house and discharges water back to the UHS portion of the cooling pond. Biocide, scale inhibitor/silt dispersant and corrosion inhibitor that are injected into the service water tunnel also serve to minimize biological fouling, microbiologically influenced corrosion, scaling, and silting within the CSCS equipment cooling water system.

Other LSCS Surface Water Systems

The plant's two storm water ponds are on the west side of the plant and receive storm water runoff from the protected area. Storm water runoff is managed by a system of surface ditches and underground piping that drain two storm water zones within the protected area. Zone I discharges to the North storm water pond and Zone II discharges to the South storm water pond. Uncontaminated runoff from Zone I flows through the North storm water pond, which then discharges to the cooling pond discharge canal via a permitted NPDES outfall. Some storm drains in Zone I are routed through the Unit 2 Oil Separator before entering the North storm water pond. Uncontaminated runoff from Zone II flows through the South storm water pond, which then discharges to the cooling pond discharge canal via another permitted NPDES outfall. Some storm drains in Zone II are routed through the Unit 1 Oil Separator before entering the South storm water pond. The areas to the northwest and south of the developed plant area are drained away by existing creeks and gullies, except for the Firing Range, from which storm water runoff flows to the South storm water pond, and a portion of the Switchyard, from which storm water runoff flows to the North storm water pond (Exelon Nuclear 2011a).

Input to the LSCS sanitary water system is supplied by deep wells, as described under "Groundwater-Supplied Systems," below. Primary (Cell #1) and secondary (Cell #2) aerated sewage treatment lagoons provide sewage treatment for the plant's sanitary water system output. Cell #1 has a capacity of 11 million L (2.9 million gal), and Cell #2 has a capacity of 3.8 million L (1.3 million gal). Both lagoons are lined with rip-rap. Sewage treatment effluent is normally treated by sand filtration, for Total Suspended Solids (TSS) reduction, and then disinfected before being discharged into the cooling pond.

Groundwater-Supplied Systems

Two deep wells supply water to the demineralized water system and the potable and sanitary water system (Exelon Nuclear 2012a). Both wells were installed during construction of the Station and draw water from depths greater than 488 m (1,600 ft) (Exelon Generation 2012a). Based on Illinois Water Inventory Program reports for years 2008 through 2012 (Exelon Generation 2008a, Exelon Generation 2009, Exelon Generation 2010a, Exelon Generation 2011a, Exelon Generation 2012a), the average pumping rate for Well #1 is 78.7 L/min (20.8 gpm) and for Well #2 is 20 L/min (5.3 gpm).

The original demineralized makeup system has been abandoned in place and replaced with a vendor trailer which supplies water suitable for makeup to the power cycle and various plant closed systems. There is no longer a makeup demineralizer regeneration capability. Raw water is pumped from the onsite wells and treated via the vendor trailer system to remove iron, manganese, and suspended matter. The trailer is capable of producing deionized water at a rate of 189 L/min (50 gpm). The filtered water is stored in the 1.3 million L (350,000 gal) storage tank. Water from the storage tank is pumped to the makeup demineralizer and potable and sanitary water systems, as required. The water from the storage tank is processed through an additional treatment system. Part of the water is chlorinated, as needed, and sent to the potable water system; the remaining water is used in the sanitary water system (Exelon Nuclear 2012a). Because the wells pump only to replenish the water used from the water storage tank, total groundwater use averages approximately 98 L/min (26 gpm).

LSCS has no active dewatering system or program for removal of groundwater in-leakage into plant structures. Historically, such in-leakage has been small and not quantified. Liquids from floor drains and sumps throughout the plant are routed based on origin to the radwaste treatment system or the wastewater treatment plant, which are described in Sections 2.2.7 and 2.2.8, respectively.

2.2.4 Stationary Air Emission Sources and Permits

Sources of nonradiological air emissions at LSCS are five diesel generators, one gasoline storage tank, and a gasoline dispensing facility equipped with vapor recovery systems. The IEPA Federally-Enforceable State Operating Permit (FESOP I.D. No. 099802AAA) restricts emissions from the diesel generators of nitrogen oxides (86 metric tons per year [95 tons per year]), carbon monoxide (22.87 metric tons per year [25.22 tons per year]), volatile organic compounds (2.72 metric tons per year [3.00 tons per year]), sulfur dioxides (6.80 metric tons per year [7.50 tons per year]), and particulate matter (2.05 metric tons per year [2.26 tons per year]). In addition to limiting emissions, the permit limits volatile organic compounds in total distillate fuel oil and gasoline usage to 1.8 metric tons per year (2 tons per year). (IEPA 2000, Attachment A, the expiration date of which has been administratively extended by a timely renewal application dated July 15, 2005 on which IEPA has not yet acted)

2.2.5 Meteorological Monitoring Program

The meteorological monitoring program at LSCS measures wind direction, wind speed, temperature, and precipitation. Stability class is calculated using one of two methods: ΔT ("delta T"; vertical temperature difference) is the principal method and sigma theta (standard deviation of the horizontal wind direction) is used when ΔT is not available Exelon Nuclear 2012a).

Meteorological instruments are placed on booms on a 122-m (400-ft) tower located approximately 0.8 km (0.5 mi) southeast of the reactor buildings. Equipment signals are sent to an instrument building with controlled environmental conditions where recording equipment and signal conditioners process and retransmit the data to the end-point users (Exelon Nuclear 2012a).

Recorded meteorological data are used to generate wind roses and to estimate airborne concentrations of gaseous effluents and offsite radiation dose. Exelon Generation ensures the instruments are calibrated, and data consistency evaluations are routinely performed to ensure maximum data integrity. Exelon's data recovery objective is to attain better than 90 percent from each measuring and recording system. (Exelon Nuclear 2012a)

2.2.6 Power Transmission System

Electricity generated by LSCS is distributed to the system grid from the onsite 345-kilovolt switchyards, which includes circuit breakers, disconnect switches, buses, and associated equipment arranged in a ring bus configuration. The switchyard connects LSCS with two 345-kilovolt transmission lines to the Plano substation and two 345-kilovolt transmission lines to Braidwood Station. In addition, the ring bus is connected to the 138-kilovolt transmission system through a 345/138 kilovolt transformer providing power to two 138 kilovolt lines to the communities of Streator and Mazon.

The switchyard provides redundant power to two system auxiliary power transformers, each with sufficient capacity to handle the auxiliary power requirements of one unit. The auxiliary power is available, through circuit breaker switching, to all emergency auxiliary equipment of both units, and therefore, serves as a redundant offsite source of essential auxiliary power. Startup auxiliary power is provided through the system auxiliary power transformers from any of the transmission system connections in the switchyard.

The main power transformers are connected via intermediate, on-site electrical components to the on-site LSCS switchyard. The LSCS switchyard is a permanent part of the overall transmission system, and thus, constitutes the location where electricity is fed into the regional power distribution system. Accordingly, Exelon Generation concludes that the offsite transmission lines connected to the LSCS switchyard are not in-scope transmission lines as defined by footnote 4 of Table B-1 of 10 CFR Part 51, Subpart A. Also, the electrical connections between the main plant and the LSCS switchyard traverse only property used for industrial purposes. Hence, no rights-of-way are maintained specifically for these connections, and electrical shock hazards are controlled on the LSCS site in accordance with applicable industrial safety standards.

2.2.7 Radioactive Waste Management Systems

The following descriptions of the radioactive waste management systems at LSCS are taken from the Updated Final Safety Analysis Report (Exelon Nuclear 2012a) unless otherwise referenced.

2.2.7.1 Liquid Radioactive Waste Systems

The liquid radioactive waste system, which serves both LSCS units, collects, monitors, and processes potentially radioactive liquid wastes produced by plant operations, while recycling as much processed liquid waste as can be accommodated within the Station water balance. LSCS operates this system using a voluntary approach that limits the release of radioactive species via the liquid pathway. Notwithstanding, radioactively-contaminated liquid discharges from the system are authorized and may occur if treated waste water is not needed for recycle. The following paragraphs describe the system more fully, including how discharges are managed should they be necessary.

Processing in the liquid radioactive waste system results in two streams: a clean product stream and a reject stream. Normally, the reject stream is processed for disposal in the solid radioactive waste system. The clean product stream is returned for use in the main plant systems through the condensate storage tanks, provided that the water quality is acceptable and the plant has need for the makeup water.

If it cannot be managed as described above, treated waste water would be sent to a discharge tank and held until a discharge batch has accumulated. Prior to releasing each discharge batch, the batch would be sampled and treated if necessary to ensure radionuclide concentrations and resulting radiation doses to Station personnel and the general public comply with NRC regulations in 10 CFR Part 20 and 10 CFR Part 50, Appendix I. The system is capable of discharging a batch directly into the cooling pond blowdown line at a maximum rate of 170 L/min (45 gpm), dependent on dilution calculations, as authorized by NPDES permit IL0048151 (Outfall E01).

The liquid radioactive waste system consists of the following major subsystems: (1) the waste processing subsystem, (2) the floor drain processing subsystem, (3) the chemical waste subsystem, and (4) the sludge subsystem common to both units. A vendor-provided liquid waste treatment system is also available to supplement plant system capabilities.

Waste processing subsystem: This subsystem collects and processes high purity (low conductivity) water from sources such as equipment drains. This water is treated by settling, filtration, and demineralization. After appropriate sampling, it is returned for Station reuse through the condensate storage tanks.

Floor drain processing subsystem: This subsystem collects and processes low purity (high conductivity) waste water from the floor drain systems. These waters are normally too high in conductivity for effective ion exchange treatment in the waste processing system and may also be high in suspended solids. After appropriate treatment and sampling, the water is normally sent to the condensate storage tanks for reuse.

Chemical waste subsystem: This subsystem processes the highest conductivity water in the liquid radioactive waste system, such as from laboratory drains and the radwaste building sump by ion exchange demineralization. Plant procedures are used to determine the disposition of the processed water, which may include discharge.

Sludge subsystem: The sludge subsystem, unlike the other subsystems, is not a processing stream, but is a group of tanks and associated pumps which serve as an interface between the liquid radioactive waste system and the solid radioactive waste handling system. After radioactive contaminants have been removed from a liquid radioactive waste system, concentrated, and treated or held up to allow radioactive decay if necessary, they are transferred to the solid radioactive waste system for processing, temporary storage at the Station, and shipment from the Station.

2.2.7.2 Gaseous Radioactive Waste Systems

The gaseous waste management systems are designed to process and control the release of gaseous radioactive wastes so that the total radiation exposure to members of the public complies with 10 CFR Part 20 and 10 CFR Part 50, Appendix I. It is also designed to ensure radiation doses are as low as reasonably achievable and do not exceed other applicable Federal regulations. This is accomplished while maintaining the occupational exposure as low as reasonably achievable and without limiting plant operation or availability.

As described in Section 2.2.1, the steam in a BWR such as LSCS Units 1 and 2 contains impurities in the form of radioactive gases that are continuously removed during plant operation from the main condenser by an air ejector. This process is the major source of radioactive gases. It generates more than all other sources combined and normally removes both activation gases and fission product noble gases. Many of these gases are short-lived and decay quickly. The off-gas treatment system removes some gases and delays the release of the remaining gases by adsorption on charcoal beds to allow time for radioactive decay. As a final step, the offgasses pass through a high efficiency particulate air (HEPA) filter, and are discharged through the monitored, 113-m (370-ft) Station vent stack.

Other plant facilities that are potential sources of radioactive gas emissions include: the primary containment, the secondary containments (reactor buildings), turbine buildings, and the radwaste building. The ventilation systems in each of these facilities have filtration and treatment systems that the air passes through before being discharged through the Station vent stack.

2.2.7.3 Solid Radioactive Waste System

The solid radioactive waste system receives, dewaters, solidifies, packages, handles, and provides temporary storage facilities for all radioactive wet solid wastes prior to offsite shipment and disposal. It also receives, decontaminates, compacts (as necessary), and provides temporary storage facilities for all radioactive dry wastes prior to offsite shipment and disposal. LSCS disposes of solid radioactive waste at facilities in Utah and Texas. The Station also utilizes offsite vendor services for dry active waste processing, including compaction, incineration, thermal processing, and sorting of the dry active waste.

Prior to July 1, 2008, Class B and Class C (Class B/C) low-level radioactive wastes from LSCS were disposed at the Energy*Solutions*, LLC Barnwell Disposal Facility in South Carolina. On July 1, 2008, the Barnwell facility, which serves the Atlantic Interstate Low-Level Radioactive Waste Management Compact (“Atlantic Compact”), ceased accepting Class B/C low-level radioactive waste shipments from out-of-compact generators, an action authorized by the Low-Level Radioactive Waste Policy Amendments Act of 1985. Because Illinois is not a member of the Atlantic Compact, this action has precluded subsequent shipments of spent resins as well as other Class B/C wastes from LSCS to the Barnwell facility.

By letter and Safety Evaluation dated July 21, 2011, the NRC issued license amendment numbers 202 and 189 to the facility operating licenses for LSCS Units 1 and 2. These license amendments allow the storage in the LSCS Interim Radwaste Storage Facility (IRSF) of Class B/C waste from Braidwood, Byron, and Clinton Stations (NRC 2011a) in addition to wastes generated at LSCS.

The LSCS IRSF has the capacity to hold 270 containers of Class B/C wastes at 135 spots (i.e., two layers of containers). This has been determined to be sufficient excess storage capacity to accommodate extended storage of the Class B/C wastes generated by the three other Exelon Generation stations. Also, beginning in 2013 Exelon Generation entered into a contract with Waste Control Specialists for treatment and disposal of Class B/C wastes at a facility in Texas, which will reduce the demand for extended onsite storage.

LSCS infrequently generates small quantities of mixed waste (i.e., waste having both a hazardous component that is subject to the requirements of the Resource Conservation and Recovery Act and a radioactive component that is subject to the requirements of the Atomic Energy Act). The IEPA regulates the hazardous component of the waste and the Illinois Emergency Management Agency Division of Nuclear Safety and NRC regulate the radioactive component. When generated, mixed wastes are accumulated in the Mixed Waste Storage Building (Building 20) in the manner provided under 35 IAC 726, Subpart N, pending transport to a licensed offsite facility for treatment and disposal.

2.2.8 Nonradioactive Waste Management Systems

Exelon Generation expects that during the license renewal term LSCS will continue to generate types and quantities of nonradioactive wastes similar to those generated during current and past operations. Types of nonradioactive wastes include hazardous, non-hazardous, and universal wastes. These are managed in accordance with applicable federal and state regulations as implemented through corporate procedures.

LSCS is a small quantity hazardous waste generator. Even so, hazardous wastes are managed at LSCS according to large quantity generator standards because the Station can be an episodic large quantity generator. For example, during one month in 2007, the Station generated more than 1,000 kg of hazardous waste in the form of sand containing spent lead ammunition that was removed from the on-site firing range. Since then, a lead management procedure has been implemented to better manage the use of lead bullets and minimize generation of lead-contaminated waste. The Station has contracts with waste haulers and off-site treatment and disposal facilities to remove and disposition all hazardous wastes.

Typical non-hazardous wastes that require off-site management include, but are not limited to: potentially infectious medical waste (PIMW), waste/used oil, grease, antifreeze, adhesives, and other petroleum-based liquids. LSCS has contracts with waste haulers, and off-site treatment and disposal facilities to properly remove and disposition such non-hazardous wastes. PIMW is generated in conjunction with the operation of the on-site health facility/on-site nurse station activities and may include used and unused sharps (i.e. hypodermic needles and syringes), and items contaminated with human blood and blood products such as bandages and clothing containing blood. The transportation and disposal of PIMW is regulated in Illinois as a unique category of special waste, and disposal of PIMW is banned at all landfills in Illinois (35 IAC 1420.104(a)).

Universal wastes include spent products such as batteries and mercury-containing lamps. These materials are managed under the standards specified in 35 IAC 733. The Station recycles universal wastes, oils, batteries, pallets, metals, paper, office wastes, and other recyclables according to Exelon Generation procedures and Illinois regulations.

LSCS operates an onsite sewage treatment plant. Sewage treatment is provided by primary and secondary aerated lagoon cells. (The lagoon cells are excavated in natural soil and include a 0.6-m (2-ft) deep clay liner to minimize seepage and leaks. The walls and berms are of compacted granular material, a 3-m (10-ft) wide geotextile liner at normal pool levels and rip rap to prevent erosion.) The effluent of the lagoon is normally treated by sand filtration, for total suspended solids reduction. Sewage treatment effluent is disinfected and then discharged (Outfall B01) into the cooling pond. LSCS also treats non-radioactive industrial wastewaters in an onsite wastewater treatment plant, which uses cationic and anionic polymers for coagulation/flocculation. The treated effluent is discharged (Outfall C01) into the cooling pond. As Section 2.2.3 describes, blowdown from the cooling pond is discharged to the Illinois River through Outfall 001 under NPDES permit IL0048151.

2.3 Refurbishment Activities

NRC

> **"The report must contain a description of … the applicant's plans to modify the facility or its administrative control procedures as described in accordance with § 54.21...This report must describe in detail …any planned refurbishment activities." 10 CFR 51.53(c)(2)**
>
> **"The environmental report must contain analyses of …refurbishment activities, if any, associated with license renewal…" 10 CFR 51.53 (c)(3)(ii)**
>
> **"…the incremental aging management activities implemented to allow operation of a nuclear power plant beyond the original 40-year license term were assumed to fall under one of two broad categories: … (2) major refurbishment actions, which usually occur infrequently and possibly only once in the life of the plant for any given item." (NRC 2013b, Section 2.1.1)**

10 CFR 54.21 requires a demonstration that the effects of aging will be adequately managed so that the intended system functions will be maintained consistent with the current licensing basis throughout the period of extended operation. The LSCS License Renewal Application contains this demonstration. No physical plant alterations or modifications have been identified as necessary in connection with the LSCS License Renewal Application. Accordingly, Exelon Generation has no plans for refurbishment or replacement activities at LSCS. Exelon Generation has addressed refurbishment activities in this Environmental Report (Appendix E to the LSCS License Renewal Application) in accordance with NRC regulations and complementary information in the NRC GEIS (NRC 2013b) for license renewal.

2.4 Programs and Activities for Managing the Effects of Aging

NRC

> **"…The report must contain a description of … the applicant's plans to modify the facility or its administrative control procedures…. This report must describe in detail the …modifications directly affecting the environment or any plant effluents …." 10 CFR 51.53(c)(2)**
>
> **"…the incremental aging management activities implemented to allow operation of a nuclear power plant beyond the original 40-year license term were assumed to fall under one of two broad categories: (1) surveillance, monitoring, inspection, testing, trending, and recordkeeping actions, most of which are repeated at regular intervals…." (NRC 2013b)**

As Section 2.3 discusses, Exelon Generation has identified no physical plant alterations or modifications that are necessary in connection with the LSCS License Renewal Application. Accordingly, there will be no modifications directly affecting plant effluents or the environment.

2.5 Employment

Exelon Generation employs approximately 880 permanent employees and 30 long-term contract employees at LSCS, a two-unit facility. Therefore, total employment is approximately 910. At 11 nuclear plants for which detailed economic data were reported in the GEIS, employment ranged from 528 workers (at a single-unit plant) to 2,385 employees (at a three-unit plant) (NRC 2013b). For the six two-unit plants, employment ranged from 666 employees to 1,683. The LSCS employment number is within this range. Fifty-seven percent of the employees live in LaSalle County, and 29 percent live in the adjacent Grundy (17 percent) and Will (12 percent) counties, in Illinois. The remaining employees are distributed across 21 counties in Illinois and 4 out-of-state locations (Tetra Tech Undated).

The LSCS units are on staggered 24-month refueling cycles. During refueling outages (lasting about 25 days each), the normal plant staff is supplemented by approximately 800 craft workers. Approximately 75 to 80 percent of these outage workers are permanent residents of the region. The remaining 20 to 25 percent stay in Morris, Ottawa, or Joliet, Illinois (Exelon Generation 2013a).

LSCS employees typically commute from or through Ottawa, Marseilles, Seneca, Morris, or Joliet (Figure 3.1-1). From Ottawa, commuters travel south on Illinois State Highway 23 (IL 23) then east on N 21st Road (County Road 6) to the plant entrance. From Marseilles, commuters take E 22nd Road (County Road 15) south to N 21st Road, then travel east to the plant entrance. From Seneca, commuters travel south on IL 170 to N 21st Road, then west to the plant entrance. Commuters from Morris and Joliet take either U.S. 6 or I-80 west to IL 170, or I-80 west to IL 170 via U.S. 6, then IL 170 south to N 21st Road and from there N 21st Road west to the plant entrance.

As described in Section 2.4, Exelon Generation has identified no need for significant new aging management programs or major modifications to existing programs. Exelon Generation anticipates that existing “surge” capabilities for routine activities, such as outages, will enable Exelon Generation to perform the increased surveillance, monitoring, inspections, testing, trending and recordkeeping (SMITTR) workload without increasing the LSCS staff. Exelon Generation has not identified any refurbishment activities necessary at LSCS. Accordingly, the current employment figures reported above are considered representative of those during the license renewal term.

In the GEIS, the NRC determined that impacts from continued plant operations over the license renewal term on employment and income, recreation, tourism, tax revenues, community services and education, population and housing, and transportation would be SMALL for all nuclear plants, and designated these Category 1 issues (NRC 2013b). Because the new and significant analysis identified no information regarding LSCS that would change the conclusions of the GEIS regarding socioeconomic issues, no further analyses are required.

2.6 Alternatives to the Proposed Action

Section 2.1 describes the proposed action, which is for NRC to renew the operating licenses for LaSalle County Station (LaSalle) Units 1 and 2 for an additional 20 years beyond the current expiration dates. Because the decision before the NRC is to renew or not renew the licenses, there is only one fundamental alternative to the proposed action: the no-action alternative. However, the no-action alternative would presumably result in a need for new electrical generating capacity in the region served by LSCS.

The no-action alternative refers to a scenario in which the NRC does not renew the LSCS operating licenses. Unlike the proposed action of renewing the licenses, denying license renewal does not provide baseload generation capability to meet future system generating needs beyond the term of the current nuclear power plant operating license. Therefore, unless replacement generating capacity is provided as part of the no-action alternative, a large amount of baseload generation would no longer be available, and the alternative would not satisfy the purpose and need for the proposed action (see Section 1.1). For this reason, the no-action alternative has two components: replacing the generating capacity of LSCS and decommissioning the LSCS facility.

Chapter 7 presents, in some detail, the methodology of identifying actions that could be taken to replace the baseload generation capacity of LSCS in the region. Alternative generating technologies were evaluated to identify candidate technologies that would be capable of replacing the LSCS generating capacity by the end of the first licensed unit's term in 2022. For purposes of this environmental report, Exelon Generation hypothesizes the following alternatives to license renewal that implement the generation replacement component of the no-action alternative.

- new coal generation capacity (Section 7.2.1.1)
- new natural gas generation capacity (Section 7.2.1.1)
- purchased power (Section 7.2.1.2)
- new nuclear generation capacity (Section 7.2.1.3)
- wind energy (Section 7.2.1.4)
- combinations of various energy supplies (Section 7.2.1.5)

Section 7.2.1.6 discusses additional alternatives that Exelon Generation has determined are not reasonable and the bases for these determinations.

Chapter 3

Affected Environment

3.1 Location and Features

LaSalle County Station (LaSalle) is in LaSalle County in northeastern Illinois, approximately 120 km (75 mi) southwest of downtown Chicago. Figure 3.1-1 shows LSCS's 80 km (50 mi) radius and Figure 3.1-2 shows the 10 km (6 mi) radius. LSCS is approximately 10 km (6 mi) southwest of Seneca, 11 km (7 mi) south-southeast of Marseilles, and 8 km (5 mi) south of the Illinois River. The area surrounding LSCS is rural and agricultural, with numerous wind turbines in the immediate vicinity and the region.

LaSalle occupies 1,568 ha (3,875 ac), of which approximately 833 ha (2,058 ac) comprise the cooling pond (ComEd 1977). The generating facilities are on the southwest portion of the site and include the reactor building and related structures, a switchyard, administration buildings, warehouses, and other structures (Figure 2.2-2).

The cooling pond was created by constructing dikes that rise above the surrounding land. The IDNR classifies the LSCS dike structure as a Class I dam (IDNR 2000). Class I dams are those for which failure has a high probability of causing loss of life or substantial economic loss, similar to that of US Army Corps of Engineers High Hazard Potential (17 Illinois Adm. Code, Ch. I, Sec. 3702, Jan 13, 1987). The cooling pond has an elevation of 213 m (700 ft) above mean sea level (msl) at normal pool elevation (ComEd 1977). IDNR leases the cooling pond, with the exception of the ultimate heat sink immediately in front of the intake canal, from Exelon Generation and manages it for public fishing (IDNR 2013). The cooling pond serves as a water supply for an IDNR fish hatchery on land adjacent to the pond that is also leased to IDNR by Exelon Generation (Exelon Generation 2013b) (Figure 2.2-2).

Underground makeup and blowdown pipelines approximately 5.6 km (3.5 mi) long connect the cooling pond to the Marseilles Pool portion of the Illinois River, which is the source of the cooling pond's makeup water and the receiving body of water for permitted discharges from the Station. The blowdown is subject to limitations established by National Pollutant Discharge Elimination System (NPDES) Permit IL0048151. The makeup and blowdown pipeline corridor right-of-way crosses the eastern portion of the Marseilles State Fish and Wildlife Area (Figure 3.1-2), a 1,032-ha (2,550-ac) area managed by IDNR for hunting and wildlife habitat. Marseilles State Fish and Wildlife Area (including the portion of the pipeline corridor that crosses it) also is used by the Illinois Army Reserve National Guard for training when hunting seasons are closed (IDNR 2013).

Illini State Park is approximately 10 km (6 mi) north-northwest of LSCS, on the south side of the Illinois River. This 206-ha (510-ac) park has facilities for camping, picnicking, boating, and fishing (ComEd 1977; IDNR 2013).

County Road 6, also known as North 21st Road and Grand Ridge-Mazon Road, runs parallel to LSCS's southern boundary and provides access to the site. State Highway 170 is 0.8 km (0.5 mi) east of the site and County Road 30, also known as East 25th Road, is slightly west of the site. Interstate Highway 80 is 13 km (8 mi) north of the site. The Chicago, Rock Island & Pacific Railroad, in this area parallel to and slightly north of the Illinois River, is the closest railroad line. A 10 km (6 mi) rail spur connects LSCS to the Atchison, Topeka, and Santa Fe Railroad south of the site (ComEd 1977).

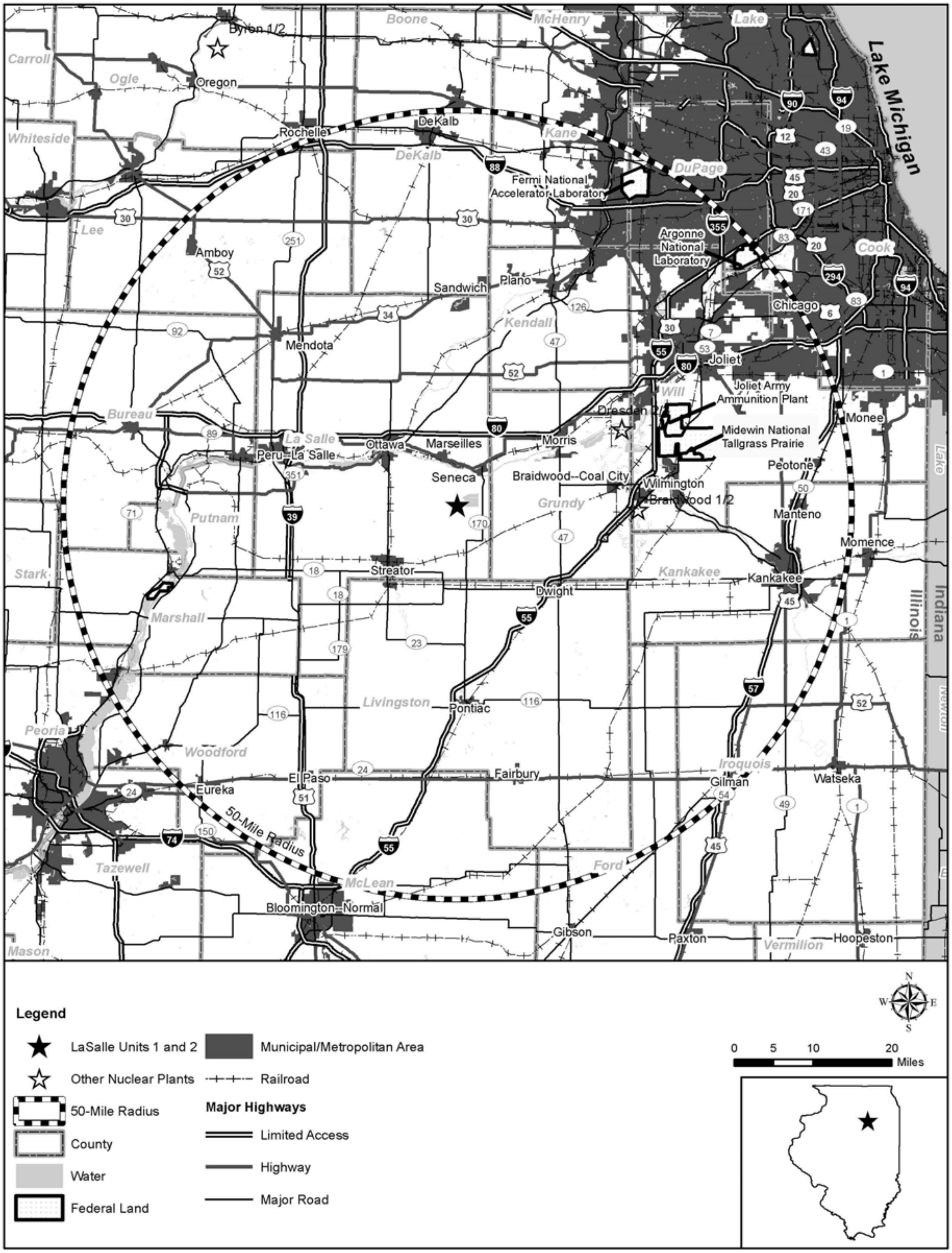

Figure 3.1-1 50 Mile (80 km) Radius Map

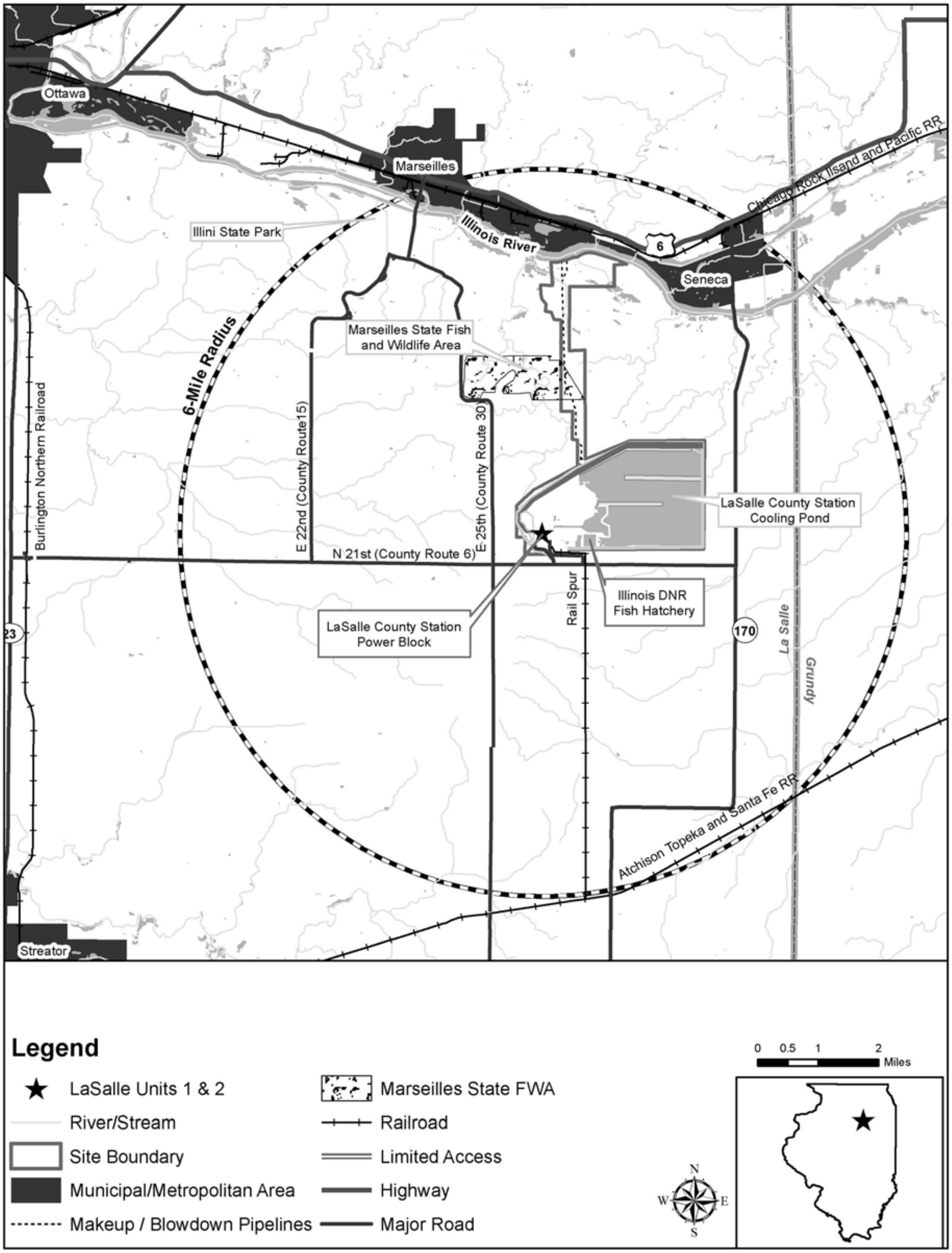

Figure 3.1-2 6 Mile (10 km) Radius Map

3.2 Land Use and Visual Resources

Offsite Land Use

Although less than 97 km (60 mi) from Chicago's southwestern city limits, LaSalle County is rural, comprised mostly (approximately 85 percent of total land area) of agricultural production (LEAMgroup and LaSalle County 2014). Land use within a 10-km (6-mi) radius of the Station is primarily agricultural, with cropland or pastures bordering the facility to the east, south, and west (see "pasture/hay" and "cultivated crop" legends on Figure 3.2-1). The bluffs overlooking the Illinois River north of the plant are mostly forested, with a scattering of residences and small farms. The broad south bank floodplain of the Illinois River is a mosaic of agricultural fields and woodlots, with more of the former than the latter. The north bank of the river is more developed, including parts of the incorporated towns of Seneca and Marseilles. Table 3.2-1 shows land cover in the 10-km (6-mi) region based on data downloaded from the National Land Cover Database 2006 (USGS 2012) and made available by the Multi-Resolution Land Characteristic's Consortium (USGS 2012).

Three areas managed by the IDNR for public use and recreation are within 10 km (6 mi) of LaSalle: LaSalle Lake State Fish & Wildlife Area, Marseilles State Fish & Wildlife Area, and Illini State Park. The LaSalle Lake State Fish & Wildlife Area comprises the areas of the LSCS cooling pond that are open to the public and a small picnic and boat launch area, and provides recreational opportunities ranging from fishing to picnicking to bird watching (IDNR 2013). It is open to the public seven days a week in the spring, summer, and fall. Opening and closing dates change from year to year, based on agency personnel availability and funding, but it is generally open from mid-March until mid-October. The Marseilles State Fish & Wildlife Area is approximately 2.4 km (1.5 mi) north of the plant (see Figure 3.1-2). It is a 1,032-ha (2,550-acre) tract of mostly-wooded land managed by IDNR for wildlife and open to the public during certain times of the year (IDNR 2013). Illini State Park is approximately 10 km (6 mi) northwest of the plant. It is 206 ha (510-ac) along a 4.8-km (3-mi) strip of land on the south bank of the Illinois River, adjacent to the area known as the Great Rapids and directly across the river from the town of Marseilles (see Figure 3.1-2) (IDNR 2013).

The Illinois Department of Commerce and Economic Opportunity expect the population of LaSalle County to increase from an historic growth rate of 2 percent per decade, to 4 percent per decade by 2030. The LaSalle County Comprehensive Plan projects that the rate of land use for residential and commercial development will grow faster than the rate of population growth, and points out that new residential development and commercial growth are following established highway corridors, including Highways 6 between LaSalle and Ottawa, north of LSCS, 251 west of LSCS, and I-80, north of LSCS (see Figure 3.1-1). (LEAMgroup and LaSalle County 2014).

Onsite Land Use

As discussed in Section 3.1 and shown in Figure 3.2-2, the 833 ha (2,058 ac) cooling pond occupies more than half (53 percent) of the 1,568 ha (3,875 ac) LSCS site. The portion of the site that lies west of the cooling pond includes the generating facilities and associated infrastructure (roads, parking lots, warehouses, switchyard), but is surrounded by undeveloped areas that are maintained as buffer areas and natural areas for wildlife. These undeveloped areas contain grassland, old field, and scrub-shrub habitats as well as scattered "tree islands" (Exelon Generation 2013b). The generating facilities and associated infrastructure occupy approximately 60 ha (150 ac), while the surrounding undeveloped areas total approximately 101 ha (250 ac). The LaSalle Fish Hatchery, which is operated by the IDNR under a lease agreement with Exelon Generation, includes several small buildings and 16 fish-rearing pools on the southwest shore of the cooling pond approximately 0.4 km (0.25 mi) east of the LSCS switchyard. Including the pools, it is approximately 18 ha (45 ac). The makeup/blowdown line corridor, which extends between the cooling pond and the Illinois River, encompasses woodlands, pastures, and wetlands, but also includes the mowed and maintained right-of-way for a portion of the LaSalle-to-Plano 345 kV transmission line.

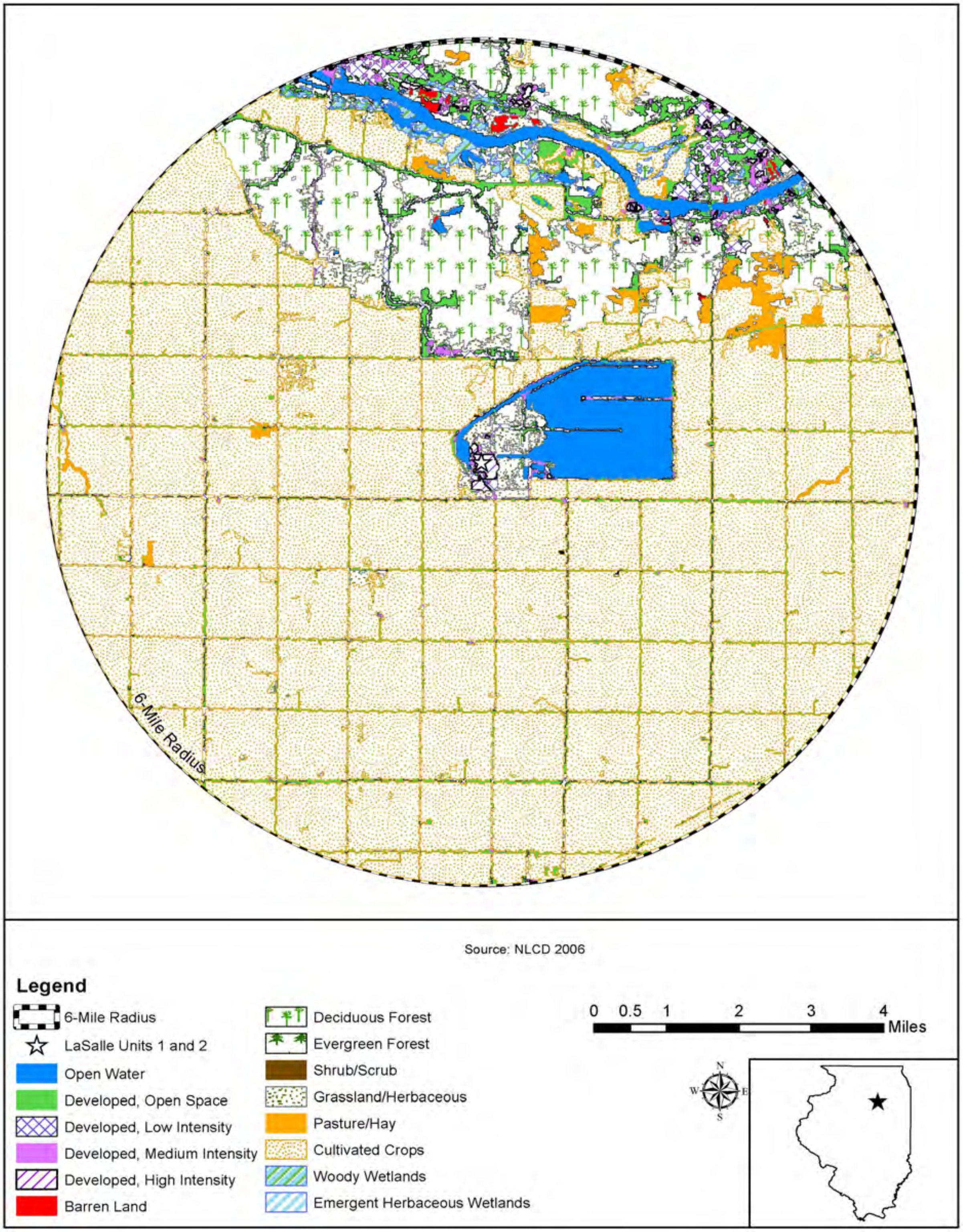

Figure 3.2-1 Land Use 6-Mile Map

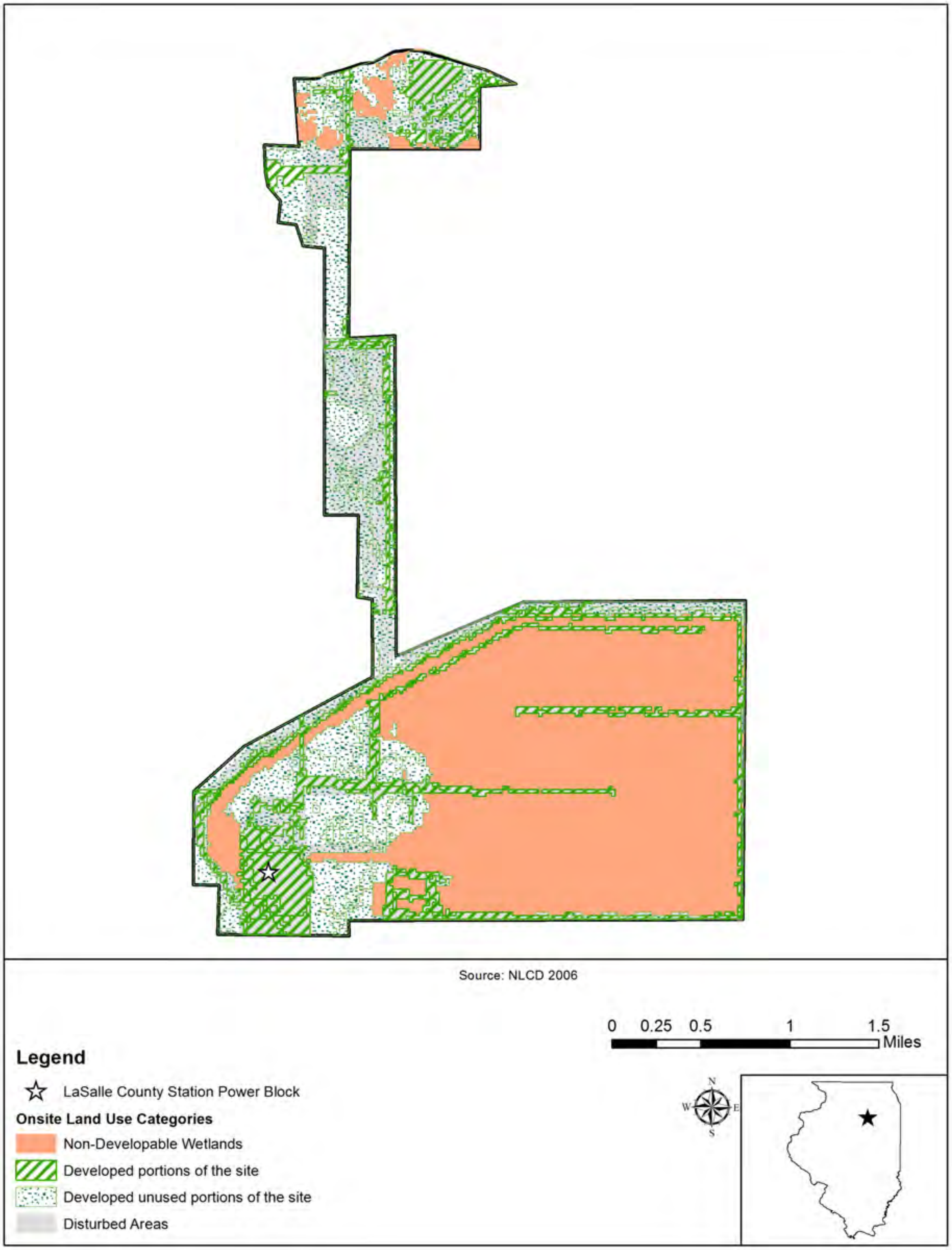

Figure 3.2-2 Land Use - Site

Visual Resources

As noted earlier, the area around LSCS is characterized by large agricultural fields and the occasional homestead, generally surrounded by hardwood ("shade") trees and outbuildings. The LSCS power block is at an elevation of approximately 216 m (710 ft) above msl, one of the highest points within a 3-km (5-mi) radius (Exelon Nuclear 2012a). The LSCS generating facilities were built more than 60 m (200 ft) above the elevation of the Illinois River to the north, and were intended to be "flood proof" (Exelon Nuclear 2012a). The Illinois River floodplain is at elevation 152 to 155 m (500-510 ft) above msl, while the river itself typically is slightly lower than the floodplain, except during times of high flow.

Although LSCS is at the top of a slope, there is slightly higher ground, from 221 to 227 m (725 to 750 ft) in elevation, immediately west and southwest of the Station. Invenergy, LLC sited the Grand Ridge Energy Center wind farm (Phase One; 66 turbines), on this north-south-trending ridge. The wind farm, with a generating capacity of 99 megawatts, became operational in October 2008 (CRE 2013). In October 2009, EDP Renewables (formerly known as Horizon Wind Energy) installed 68 wind turbines south and east of the Station, in the Ransom-Kinsman area. This wind farm, known as Top Crop I, has a generating capacity of 102 megawatts (CRE 2013).

Therefore, the viewscape is dominated by the more than 100 wind turbines which have been installed within a 10-km (6-mi) radius of the Station. The wind turbines stand 118.5 m (389 ft) tall, with a hub height of 80 m (262.5 ft) and rotor blades 38.5 m (126.5 ft) long (GE Energy 2009). The photograph below shows a typical homestead (bottom right of photograph) in the vicinity of LSCS, with wind turbines installed on adjoining farmland.

Figure 3.2-3 Viewshed near LaSalle County Station

The tallest structure on the LSCS site (excluding the meteorological tower), the Station vent stack, is 113 m (370 ft) tall (Exelon Nuclear 2012a). The largest and most visually obtrusive buildings are the co-located reactor and turbine buildings, which are 56 m (185 ft) and 41 m (134 ft) tall, respectively (NRC 1978). The photograph below shows the meteorological tower (on the right, between two wind turbines), the Station vent stack (center of photo, with "barber pole" appearance), the reactor building (the taller of the two buildings in the center of the photograph), and the turbine building (the longer, lower-standing building in the center of the photograph).

Figure 3.2-4 LaSalle County Station

A motorist travelling north on Highway 170 (the main travel route in the area) from the village of Ransom to the town of Seneca would see wind turbines to the west, south, and east until cresting the bluffs of the Illinois River at around elevation 200 m (650 ft) above msl, and would lose sight of these turbines as the highway descends to approximately 152 m (500 ft) above msl at the bridge across the Illinois River. The densest concentration of wind turbines is on the north-west trending ridge west-southwest of the Station. Wind turbines are also found scattered between the villages of Ransom and Verona, southeast of the Station and just outside of the 10-km (6-mi) radius. From virtually any vantage point, the Station (turbine building, reactor building, and stack) is less visually obtrusive than the wind turbines that surround it.

Table 3.2-1 Land Use in the 10-km (6-mi) Radius of LSCS

Land Cover Class	Hectares (acres)	Percent of 10-km (6-mi) Radius
Open Water	1,178 (2,912)	4
Developed, Open Space	1,397 (3,453)	5
Developed, Low Intensity	1,111 (2,745)	4
Developed, Medium Intensity	152 (376)	1
Developed, High Intensity	77 (191)	<1
Barren Land	44 (109)	<1
Deciduous Forest	3,410 (8,427)	12
Evergreen Forest	2 (4)	<1
Shrub/Scrub	1 (3)	<1
Grassland/Herbaceous	866 (2,190)	3
Pasture/Hay	392 (968)	1
Cultivated Crops	20,450 (50,534)	70
Woody Wetlands	176 (434)	1
Emergent Herbaceous Wetlands	2 (4)	<1
Total	29,258 (72,350)	100

In the GEIS, the NRC determined that onsite land use impacts, offsite land use impacts, and aesthetic impacts from continued plant operations over the license renewal term would be SMALL for all nuclear plants, and designated these Category 1 issues (NRC 2013b). Because the new and significant analysis identified no information regarding LSCS that is different from the assumptions in the GEIS or that would change the conclusions of the GEIS regarding land use or visual resources, no further analyses are required.

3.3 Meteorology and Air Quality

LSCS is in LaSalle County, Illinois, approximately 10 km (6 mi) southwest of Seneca, Illinois and 97 km (60 mi) southwest of the western part of Chicago. The climate of north-central Illinois is continental, with characteristic wide ranges in temperature. LSCS lies within the principal paths of cyclonic and anti-cyclonic pressure systems that track east and northeast through the area during the winter and spring. These pressure systems can result in frequent large temperature fluctuations (NRC 1978).

The polar jet stream often flows near or over Illinois, especially in fall, winter and spring. This creates low-pressure storm systems characterized by clouds, winds and precipitation (Changon, et al. 2004). Because of the location of LSCS with respect to principal storm tracks and contrasting air masses alternating over the area, severe weather is not uncommon (NRC 1978). Illinois averages 29 tornadoes annually. Peak months are April, May and June (63 percent of the total), but tornadoes have occurred in all months. Thunderstorms are common in Illinois and account for 50 to 60 percent of annual precipitation. Nearly half of all thunderstorm days occur during June, July and August (Changon, et al. 2004).

Based on climatological data from the Ottawa 5 SW weather station, 24 km (15 mi) northwest of LSCS, the coldest weather occurs in January (-5.89°C [21.4°F] on average) and the warmest occurs in July (23.44°C [74.2°F] on average) (NCDC 2004). Average annual precipitation at the Ottawa 5 SW weather station for the 30-year period 1971 - 2000 was 90.7 centimeters (cm) (35.7 inches [in]), with the least amount of rainfall recorded, on average, in the month of February (3.3 cm [1.3 in]) and the most recorded in June (10.4 cm [4.1 in]) (NCDC 2004). Meteorological information, as it relates to the analysis of severe accidents, is included in Appendix F.

Under the Clean Air Act (CAA), the U.S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS) that specify maximum concentrations for carbon monoxide (CO), particulate matter with aerodynamic diameters of 10 microns or less (PM_{10}), particulate matter with aerodynamic diameters of 2.5 microns or less ($PM_{2.5}$), ozone, sulfur dioxide (SO_2), lead, and nitrogen dioxide (NO_2). Areas of the United States with air quality as good as or better than the NAAQS are designated by the EPA as "attainment areas." Areas with air quality worse than the NAAQS are designated by the EPA as "nonattainment areas." Areas that were designated nonattainment and subsequently re-designated as attainment after meeting the NAAQS are termed "maintenance areas." States with maintenance areas are required to develop air quality maintenance plans as elements of their State Implementation Plans (SIP).

LaSalle County is in the North Central Illinois Intrastate Air Quality Control Region (40 CFR 81.262) and is currently designated as attainment for all NAAQS (40 CFR 81.314). The closest non-attainment area (for 8-hour ozone NAAQS and the annual $PM_{2.5}$ NAAQS) is the Metropolitan Chicago Interstate Air Quality Control Region, whose nearest point is approximately 27 km (17 mi) east of LSCS (Figure 3.3-1).

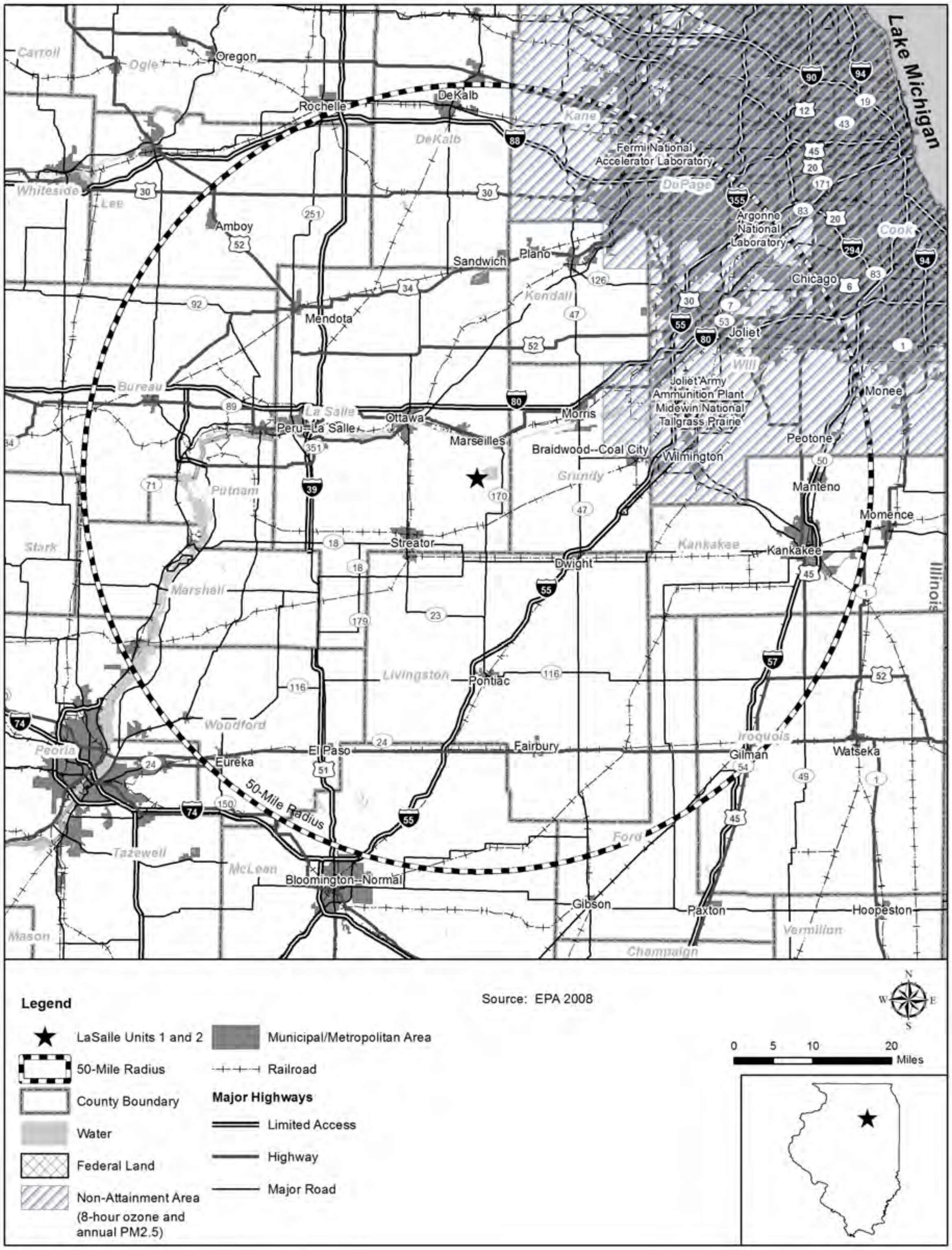

Figure 3.3-1 Air Quality within 50 Miles (80 km) of LSCS

LSCS has emission sources permitted through its Federally Enforceable State Operating Permit (FESOP), including five emergency diesel generators, each rated at 26 million BTU/hr and a 7,600 L (2,000 gal) petroleum fuel storage tank with dispensing facilities equipped with vapor recovery systems. The FESOP limits fuel consumption to a combined total for all five emergency generators to 302,800 L/month (80,000 gal/month) and 1,575,000 L/yr (416,000 gal/yr). The annual gasoline throughput for the petroleum fuel storage tank is limited to 189,271 L/yr (50,000 gal/yr). Combined emissions of pollutants from all emission sources at LSCS are limited to less than major source thresholds, but annual pollutant-specific limits are also established by permit, as follows:

- NO_x from emergency diesel generators - 86 metric tons/yr (95 tons/yr);
- CO from emergency diesel generators - 22.88 metric tons/yr (25.22 tons/yr);
- particulate matter from emergency diesel generators - 2.05 metric tons/yr (2.26 tons/yr);
- volatile organic material from emergency diesel generators and the gasoline storage tank - 2.7 metric tons/yr (3.00 tons/yr) and 1.8 metric tons/yr (2.00 tons /yr), respectively; and
- SO_2 from emergency diesel generators - 6.80 metric tons/yr (7.50 tons/yr).

As reported and submitted to IEPA, actual total emissions from all sources at LSCS from 2008 to 2012 are shown in Table 3.3-1.

On March 3, 2010, the U.S. Environmental Protection Agency (EPA) issued a final rule to reduce emissions of hazardous air pollutants from existing diesel powered stationary reciprocating internal combustion engines (RICE) (40 CFR Part 63). These engines also are known as compression ignition (CI) engines. LSCS is subject to this rule as an area source of hazardous air pollutants. Notwithstanding, the total annual quantity of hazardous air pollutants from LSCS sources is well below the hazardous air pollutants' significance level of 10 tons per year. Hence, hazardous air pollutants are not reported for LSCS.

In October 2009, the EPA issued the Mandatory Reporting of Greenhouse Gases Rule (74 FR 56260 [October 30, 2009]), which requires reporting of greenhouse gas (GHG) emissions data and other relevant information from large sources and suppliers of these gases in the United States. The rule was implemented as the Greenhouse Gas Reporting Program. Facilities that emit 25,000 metric tons or more per year of GHGs are required to submit annual reports to the EPA. On May 13, 2010, the EPA issued a final rule that addressed GHG emissions from stationary sources under the CAA permitting programs. The Greenhouse Gas Tailoring Rule set thresholds for GHG emissions that define when permits under the Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs are required to limit GHG emissions from new and existing industrial facilities. The GHG Tailoring Rule addresses emissions of a group of six GHGs: CO, methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) (75 FR 31514 [June 3, 2010]). The volume of GHG direct emissions at LSCS is small, because LSCS does not burn fossil fuels to generate electricity. However, Exelon Generation has adopted a procedure to assist its parent company, Exelon Corporation, in complying with the U.S. EPA's Greenhouse Gas Reporting program and the International Standards Organization 14064 Greenhouse Gases—Part 1 specification. In accordance with the procedure, potential direct and indirect GHG sources have been identified for LSCS, and data are collected and submitted to a central corporate database for use in quantifying site-wide GHG emissions. GHG data for mobile sources are not compiled or reported, except those under corporate control (fleet vehicles). Within Exelon Generation, GHG emissions from fleet vehicles are tracked through fleet fuel usage. The data are tracked for the Exelon Generation fleet rather than individual facilities. Therefore, no information on emissions from vehicles specific to LSCS is readily available. The site-wide LSCS GHG emission inventory [GHG CO_2 Equivalents (metric tons)] for 2013 is provided in Table 3.3-2.

The CAA, as amended, established Mandatory Class I Federal Areas where visibility is an important issue. The closest Class I areas to LSCS are Mammoth Cave National Park, approximately 494 km (307 mi) to the south-southeast, in Kentucky, and the Mingo Wilderness Area, approximately 489 km (304 mi) to the south-southwest, in Missouri (EPA 2011).

In the GEIS, the NRC determined that impacts to air quality from continued plant operations over the license renewal term would be SMALL for all nuclear plants, and designated these Category 1 issues (NRC 2013b). Because the new and significant analysis identified no information regarding LSCS that would change the conclusions of the GEIS regarding air quality, no further analyses are required.

Table 3.3-1 LSCS Air Emissions (2008 – 2012)

Pollutant	2008 Reported Emissions [metric tons (tons) per year]	2009 Reported Emissions [metric tons (tons) per year]	2010 Reported Emissions [metric tons (tons) per year]	2011 Reported Emissions [metric tons (tons) per year]	2012 Reported Emissions [metric tons (tons) per year]
CO	1.10 (1.22)	1.76 (1.94)	1.65 (1.82)	1.52 (1.68)	2.01 (2.22)
CO_2	-	-	315.79 (348.10)[a]	295.46 (325.69)	390.91 (430.91)
NH_3	0.0076 (0.0084)	0.012 (0.013)	0.011 (0.012)	0.11 (0.012)	0.014 (0.015)
NO_X	4.18 (4.61)	6.62 (7.30)	6.21 (6.85)	5.73 (6.32)	7.58 (8.36)
PM_{10}	0.075 (0.083)	0.12 (0.13)	0.11 (0.12)	0.10 (0.11)	0.14 (0.15)
$PM_{2.5}$	0.075 (0.083)	0.12 (0.13)	0.11 (0.12)	0.10 (0.11)	0.14 (0.15)
SO_2	0.0042 (0.0046)	0.0017 (0.0019)	0.0021 (0.0023)	0.0017 (0.0019)	0.0021 (0.0023)
VOC	0.25 (0.28)	0.33 (0.36)	0.32 (0.35)	0.30 (0.33)	0.35 (0.39)

[a] 2010 value for CO_2 is reported in 2011 annual report (Exelon Generation 2012b)
- = Not reported
Source: Exelon 2009, Exelon Nuclear 2010, Exelon 2011a, Exelon Generation 2012b, Exelon 2013
CO = carbon monoxide
CO_2 = carbon dioxide
NH_3 = ammonia
NOx = nitrogen oxides
PM_{10} = particulate matter with aerodynamic diameters of 2.5 microns or less
$PM_{2.5}$ = particulate matter with aerodynamic diameters of 10 microns or less
SO_2 = sulfur dioxide
VOC = volatile organic compounds

Table 3.3-2 LSCS GHG Emission Inventory in 2013 [CO_2 Equivalents (metric tons [tons])]

Direct	Metric tons (tons)
Direct Stationary Combustion	245 (270)
Direct CO_2 Fugitive	2,508 (2,765)
HFC / PFC Refrigerants	3 (3)
Indirect	
Purchased Electricity	30,520 (33,642)
Supplemental	
Ozone Depleting Refrigerants	952 (1,049)

CO_2 = carbon dioxide

HFC = hydrofluorocarbons

PFC = perfluorinated compounds

3.4 Noise

LSCS pumps, turbines, generators, switchyard equipment, transformers, and loudspeakers all generate intermittent or constant noise. Most equipment is inside structures, reducing the outdoor noise level. LSCS facilities that produce noise are more than 300 m (1,000 ft) from the nearest site boundary and 1.1 km (0.7 mi) from the nearest residence (Exelon Nuclear 2012a). The Illini State Park is approximately 10 km (6 mi) from LSCS, well beyond the range of LSCS noise.

Neither Illinois nor LaSalle County has regulations or guidelines for environmental noise. A noise survey has not been conducted at LSCS. Noise from the Station could be heard at nearby residences considering their distance from the Station, the flat terrain, and the lack of forested land between the Station and the nearest homes. However, as described in Section 3.2, land use in the vicinity of the Station is predominantly agricultural. Hence, the large expanses of cultivated land attenuate noise from operations to some extent, and LSCS personnel are aware of no concerns from residents regarding level, timing, or duration of noise. Noise levels during the license renewal term are not expected to increase in comparison to existing conditions.

In the GEIS, the NRC determined that impacts of noise from continued plant operations over the license renewal term would be SMALL for all nuclear plants, and designated these Category 1 issues (NRC 2013b). Because the new and significant analysis identified no information regarding LSCS that would change the conclusions of the GEIS regarding noise, no further analyses are required.

3.5 Geologic Environment

LSCS is in the Bloomington Ridge Plain subsection of the Till Plains section of the Central Lowland Province (Visocky, et al. 1985). Geology at the site consists of surficial deposits underlain by bedrock. The site may be divided into two portions, the upland portion which is on a glacial moraine, and the valley bottom portion on the floodplain of the Illinois River (Figure 3.5-1) (Exelon Nuclear 2012a). The power block and the cooling pond are on the upland portion; the river screen house is on the valley bottom portion. The upland moraine is topographically separated from the valley bottom floodplain by the Illinois River bluff. The maximum topographic relief from the upland moraine to the valley bottom floodplain is approximately 77.7 m (255 ft) (Exelon Nuclear 2012a).

Uplands Surficial Geology

The site is underlain by a thin veneer of Pleistocene Richland Loess, which consists of windblown silt. This unit has been modified by weathering to slightly clayey silt. The Richland Loess overlies the Wedron Formation and is the uppermost soil stratum in the upland portion of the site. The loess ranges from 1.2 to 2.4 m (4 to 8 ft) thick (Exelon Nuclear 2012a).

The Pleistocene Wedron Formation underlies the Richland Loess and ranges in thickness from 36.6 to 42.7 m (120 to 140 ft) beneath the power block and cooling pond. The formation consists of silty clay till with localized sand and gravel deposits of glacial outwash that most likely occur as scattered, disconnected bodies (Exelon Nuclear 2012a). The thickness of the Wedron Formation decreases northward toward the dissected uplands where the unit has been eroded along tributary ravines and the bluff of the Illinois River (Figure 3.5-1).

The site is over a saddle in the bedrock topography that functions as a drainage divide between two buried bedrock valleys. In the site vicinity, the buried bedrock valleys are 2.4 to 4.8 km (1.5 to 3 mi) wide and are filled with glaciofluvial deposits consisting mainly of sandy gravels and gravelly sands with lesser amounts of silt and clay in the matrix and in scattered thin layers. An exposure of one of the buried valleys near Seneca reveals 4.3 m (14 ft) of sand and clayey gravel overlying 6.1 m (20 ft) of very clean, very well-sorted medium sand (Exelon Nuclear 2012a).

Valley Bottom Surficial Geology

The Illinois River valley bottom is underlain by Pleistocene alluvium, colluvium, terraces, and swamp deposits. These units are not found in any stratigraphic sequence in the river valley. Unit descriptions are provided in Table 3.5-1.

The Cahokia Alluvium in the valley bottom is a discontinuous, surface valley fill deposit on the floodplain of the river. The unit includes alluvial fan material located at the mouths of tributary stream valleys. The alluvium is poorly-sorted sandy or clayey silt with lenses of sand and gravel. In some areas of the floodplain, localized channel scouring has removed the alluvium and older sediments and has exposed the underlying Pennsylvanian bedrock. Where present, the alluvium is generally 0.6 to 1.2 m (2 to 4 ft) thick, but may be thicker (1.2 to 6.1 m [4 to 20 ft]) in abandoned channels and tributary alluvial fans (Exelon Nuclear 2012a).

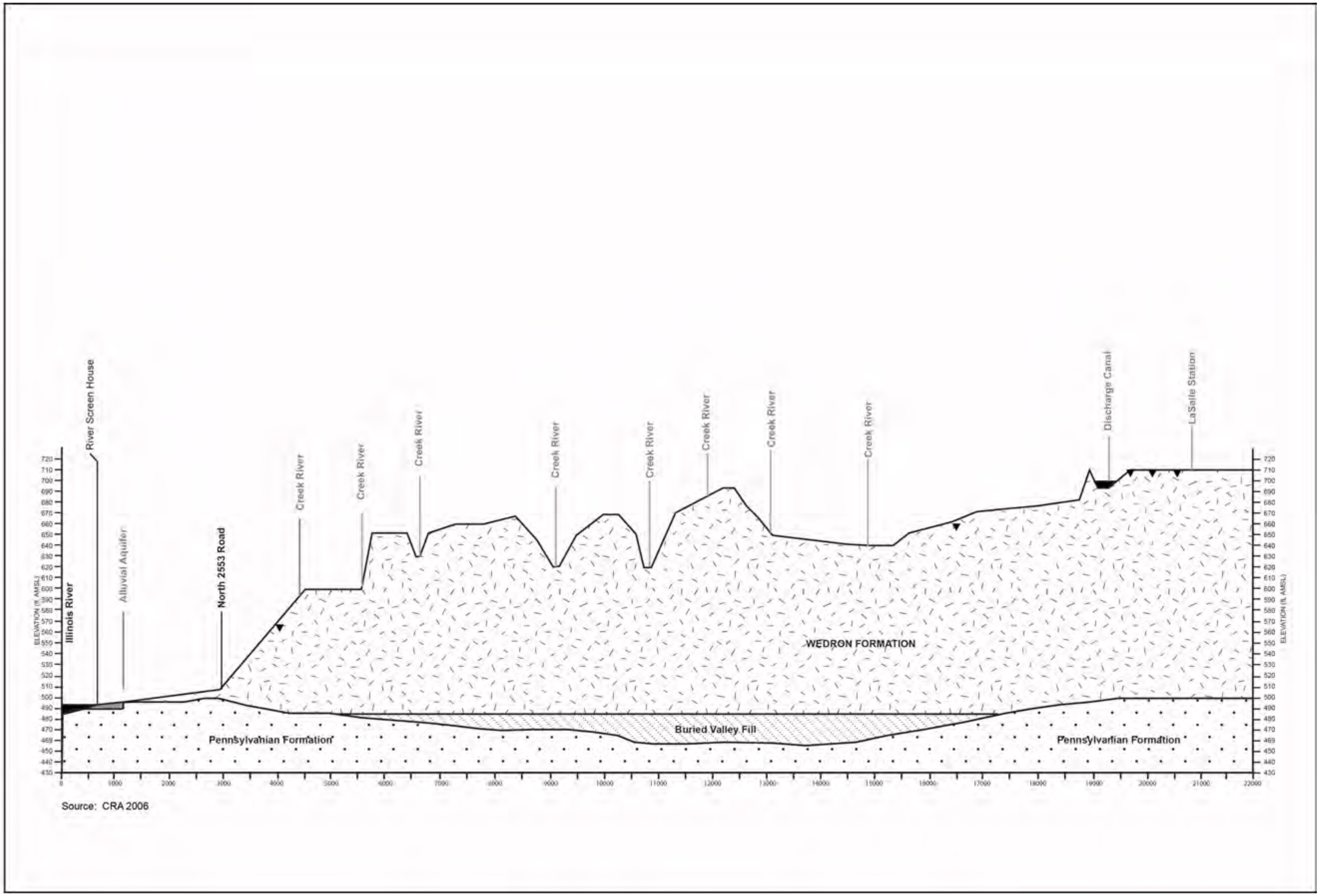

Figure 3.5-1 Geologic Cross Sections

The Peyton Colluvium occurs in the valley bottom as linear deposits of poorly-sorted colluvial sediments along the slopes of the river bluffs. This formation is predominantly pebbly, clayey silt, but its composition depends on the adjacent slope material. The thickness of the colluvium is variable, with a maximum thickness of about 12.4 m (40 ft) (Exelon Nuclear 2012a).

The Henry Formation occurs primarily as low terraces that are composed of dolomite, generally cobbly, coarse gravel underlain by finer sandy gravel. The terrace surface, 6.1 to 9.1 m (20 to 30 ft) above the floodplain, has numerous ridges or bars as much as 6.1 m (20 ft) high (Exelon Nuclear 2012a).

The Grayslake Peat is a discontinuous surficial deposit found on the floodplain. It often has high clay or silt content and is usually described as muck or silt-rich organic material. The thickness of the peat in most areas is not known, but the deposits in the floodplain lakes and ponds probably do not exceed 1.5 to 3.1 m (5 to 10 ft) (Exelon Nuclear 2012a).

Bedrock Geology

Bedrock underlying the Uplands and Valley Bottom include nearly flat-lying Pennsylvanian strata unconformably overlying Ordovician and Cambrian strata. Unit descriptions are provided in Table 3.5-1.

Pennsylvanian

The Pennsylvanian strata are approximately 53.6 m (176 ft) thick beneath the site and consist of cyclotherm sequences (limestones, shales, sandstones, coals) of the Carbondale and Spoon Formations. The Carbondale Formation forms the erosional bedrock surface for most of the site area. The formation is composed of alternating strata of shale, sandstone, clay, coal, limestone, siltstone, and many intergradation types. The thickness of the formation at the site (based on site borings) is 46 m (151 ft) (Exelon Nuclear 2012a).

The Spoon Formation has a total thickness of 7.6 m (25 ft) and is comprised of a 1.5 m (5 ft) layer of clay underlain by 6.1 m (20 ft) of gray shale. In the site area, the base of the Spoon Formation rests unconformably on the Ordovician Platteville Group (Exelon Nuclear 2012a).

Ordovician

The Ordovician strata are approximately 198.1 to 213.4 m (650 to 700 ft) thick beneath the site and consist of the Platteville, Ancell and Prairie du Chien Groups. The Platteville Group is composed of dense and fine- to medium-grained limestones with small amounts of clay and chert. The thickness of the group is variable and at the site on the order of 15.2 to 30.5 m (50 to 100 ft). The contact between the Platteville Group and Ancell Group is an unconformable thickness (Exelon Nuclear 2012a).

The Ancell Group consists of the Glenwood Formation and St. Peter Sandstone. The Glenwood Formation consists primarily of rounded, pyritic sandstone. The estimated thickness of the formation at the site is 3.1 m (10 ft) (Exelon Nuclear 2012a).

The St. Peter Sandstone is composed primarily of fine- to medium-grained, exceptionally pure quartz sand. The estimated thickness of this sandstone unit at the site is 68.6 m (225 ft) (Exelon Nuclear 2012a).

The Prairie du Chien Group consists of cherty dolomite; porous dolomitic sandstone; fine- to coarse-grained cherty dolomite; and loosely cemented, fine- to medium-grained sandstone. The estimated thickness of the group at the site is 111.3 m (365 ft) (Exelon Nuclear 2012a).

Cambrian

The Cambrian strata are approximately 1,048 m (3,440 ft) thick beneath the site and consist of the Potosi Dolomite, the Franconia Formation, the Ironton Sandstone, the Galesville Sandstone, the Eau Claire Formation, and the Mt. Simon Sandstone.

The Potosi Dolomite is a cherty, locally sandy, fine-grained dolomite with a few lenses of medium-grained, dolomitic sandstone. The estimated thickness of the dolomite beneath the site is 53.3 m (175 ft) (Exelon Nuclear 2012a).

The Franconia Formation is a fine-grained dolomitic sandstone interbedded with glauconitic dolomites and shales. At the site, the estimated thickness of the formation is 48.8 m (160 ft) (Exelon Nuclear 2012a).

The Ironton Sandstone is a medium-grained, well-graded dolomite-cemented sandstone. At the site, the estimated thickness of the Ironton Sandstone is 23 m (75 ft) (Exelon Nuclear 2012a).

The Galesville Sandstone is a clean to locally silty, fine-grained, moderately poorly-graded sandstone. At the site, the estimated thickness of the Galesville Sandstone is 24 m (80 ft) (Exelon Nuclear 2012a).

The Eau Claire Formation is fine- to coarse-grained, sometimes glauconitic, dolomitic sandstone with dolomitic, silty shale and sometimes sandy, fine-grained dolomite. At the site, the formation is estimated to be 137 m (450 ft) thick (Exelon Nuclear 2012a).

The Mt. Simon Sandstone is a fine- to coarse-grained sandstone with thinly bedded shale. At the site, the formation has an estimated thickness of 762 m (2,500 ft) (Exelon Nuclear 2012a).

The Illinois State Geological Survey has reported the occurrence of slump or rotational type landslides along the bluffs of the Illinois River, where Pennsylvanian clays and shales crop out; however the nearest landslide in the clays and shales was along the south bluff of the river more than 32 km (20 mi) from the site. Some minor sliding has been observed in the Quaternary deposits along the Illinois River near the site. The closest of these minor slides occurs approximately 6 km (4 mi) northeast of the site near Deadly Run. Because of their size, these minor slides present no hazard to the site (Exelon Nuclear 2012a).

Mineral Resources

Mineral resources that are mined near the site include sand and gravel; silica sand; clay and shale; and coal. The closest sand and gravel pits to the site are located on terraces adjacent to the river approximately 8 km (5 mi) north of the site (Exelon Nuclear 2012a). The pits may cover several acres, but are shallow and present no hazard to the plant from subsidence or collapse.

Silica sand for industrial use is removed from quarries near Ottawa, approximately 26 km (16 mi) west of the site. These quarries do not represent any possible hazard to the site. The nearest coal mine is a former strip mine 16 km (10 mi) west of the site. There has been no mining in the county since 1960. Clay and shale have been mined within 16 km (10 mi) of the site. At this distance, the mine presents no possible hazard (Exelon Nuclear 2012a).

The location of the plant does not preclude the development of any known unique mineral deposits (Exelon Nuclear 2012a).

3.5.1 Soils

The site is located in the Northern Illinois and Indiana Heavy Till Plain Major Land Resource Area (USDA 2008). Eighty-five percent of the soil in LaSalle County is designated as prime farmland and nine percent is farmland of state importance (LEAMgroup and LaSalle County 2014). Soil series in LaSalle County have been mapped by the Natural Resource Conservation Service (NRCS) in cooperation with the University of Illinois Agricultural Experiment Station. Seven soil series are present within the upland portion of the site, and seven soil series are present in the river valley. All of the soil series are developed in loess overlying glacial till (USDA 2008). The distribution of these soil series is shown on Figure 3.5-2. The characteristics and erosional potential of each series are presented in Table 3.5-2.

The upland portion of the site has three predominant soil series: the Swygert silt clay loam, the Bryce silty clay, and the Rutland silty clay loam. Swygert soils are developed in loess over silty clay glacial till forming ground moraines or end moraines (USDA 2008); Bryce soils are developed in loess over silty clay glacial till forming ground moraines or glacial lake bottoms (USDA 2008); the Rutland soils are developed in loess over silty clay glacial till forming ground moraines or lake plains (USDA 2008).

The portion of the site in the river valley also has three predominant soil series (USDA 2008): the Faxon loam, the Peotone silty clay loam, and the Channahon-Hesch fine sandy loam. Faxon soils are developed in drift over sand forming outwash plains or stream terraces; Peotone soils are developed in loess over silty clay glacial till forming ground moraines or glacial lake bottoms; Channahon-Hesch soils are developed in drift over sand, forming outwash plains or stream terraces.

Prior to construction of LSCS, Exelon Generation conducted extensive subsurface materials investigations. Static and dynamic tests of the subsurface materials across the property indicated that the site soils are suitable for the facility (Exelon Nuclear 2012a). The tests also concluded that subsurface materials will not liquefy under the site earthquake loading. In addition, no additional settlement is anticipated due to seismic loads (Exelon Nuclear 2012a).

Backfill was used around the main buildings and underground piping. The majority of the backfill used at the site consisted of Wedron silty clay till excavated from the site, which had been stockpiled for this purpose. Well-graded sand from an offsite source at Illinois Route 170 and the south bank of the Illinois River was used for select areas (Exelon Nuclear 2012a).

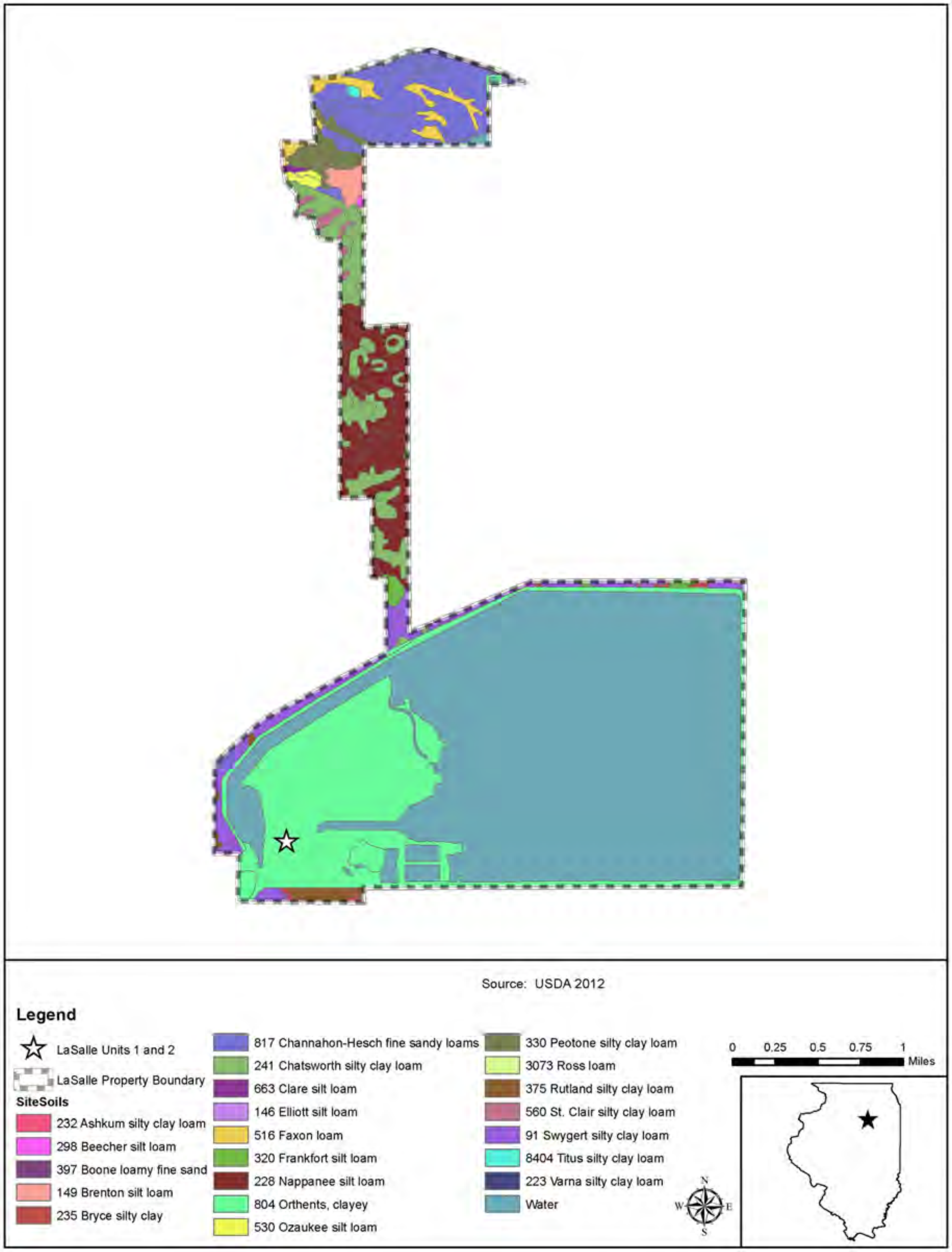

Figure 3.5-2 Agricultural Soil Characterization Map

Following initial construction, the areas surrounding the Station were graded to control runoff and minimize erosion. Many areas were revegetated to support this effort (Exelon Nuclear 2011a). No refurbishment activities are planned for the site over the extended license renewal period. Should soil disturbance activities occur, transport and erosion prevention will be managed in accordance with the site's Storm Water Pollution Prevention Plan (SWPPP).

3.5.2 Seismic Setting

Regional Seismic Setting

Illinois has two major seismic zones, the Wabash Valley Seismic Zone and the New Madrid Seismic Zone (NMSZ). The Wabash Valley Zone lies between southeastern Illinois and southwestern Indiana about 518 km (322 mi) from the site (IEMA Undated). Between 1881 and 2010, the Wabash Valley Seismic Zone spawned four earthquakes of intensity V on the Modified Mercalli Scale (MM) (Merino, et al. 2010).

The NMSZ is found in southern Illinois, Missouri, Kentucky, and Tennessee about 483 km (300 mi) from the site (Figure 3.5-3). The NMSZ is capable of producing very powerful earthquakes. The possibility of damage to areas of Illinois from earthquakes originating outside the state is dominated by the threat of a repeat of the 1811-1812 New Madrid earthquakes, which were three very large earthquakes near the town of New Madrid, Missouri. On the basis of the large area of damage (600,000 km^2 [231,661 mi^2]), the widespread area of perceptibility (5 million km^2 [1,930,511 mi^2]), and the complex physiographic changes that occurred, the New Madrid earthquakes of 1811-1812 most likely had intensities of X (MM) and were some of the largest ever recorded in the United States (USGS 2013a).

The Charleston, Missouri, earthquake of 1895 was recorded at a magnitude 6 on the Richter scale and a maximum intensity of VII (MM), and is considered the most severe shock in the NMSZ since the New Madrid earthquakes. The earthquake caused severe damage in some southern Illinois towns, but intensity observed in the area of LSCS was probably less than magnitude 4 on the Richter scale and a maximum intensity of IV (MM) or less (Exelon Nuclear 2012a).

The historical record of earthquakes with epicenters in Illinois began in 1795. During the past 218 years, there have been about 200 earthquakes in Illinois, only nine of which were strong enough to cause minor damage. The largest Illinois earthquake recorded occurred on November 9, 1968, and had a measured magnitude of 5.2 on the Richter scale and maximum intensity of VI (MM) (ISGS 1995). The earthquake epicenter was in south-central Illinois 80.5 m (50 mi) west from Evansville, Indiana, and 169 km (105 mi) northeast of New Madrid. The epicenter's distance from the LSCS site was 370 km (230 mi), and its observed site intensity was magnitude 4 on the Richter scale and a maximum intensity of IV (MM) (Exelon Nuclear 2012a).

Local Seismic Setting

The site lies in the Illinois Basin seismotectonic region, in which maximum events of VII (MM) occur. Seismotectonic regions can be defined from the relationship of historic seismicity to geologic basement structure, folds, faults, and other tectonic features. Within the past 218 years, maximum reported earthquake intensity felt at the site has not exceeded VI (MM) (Exelon Nuclear 2012a).

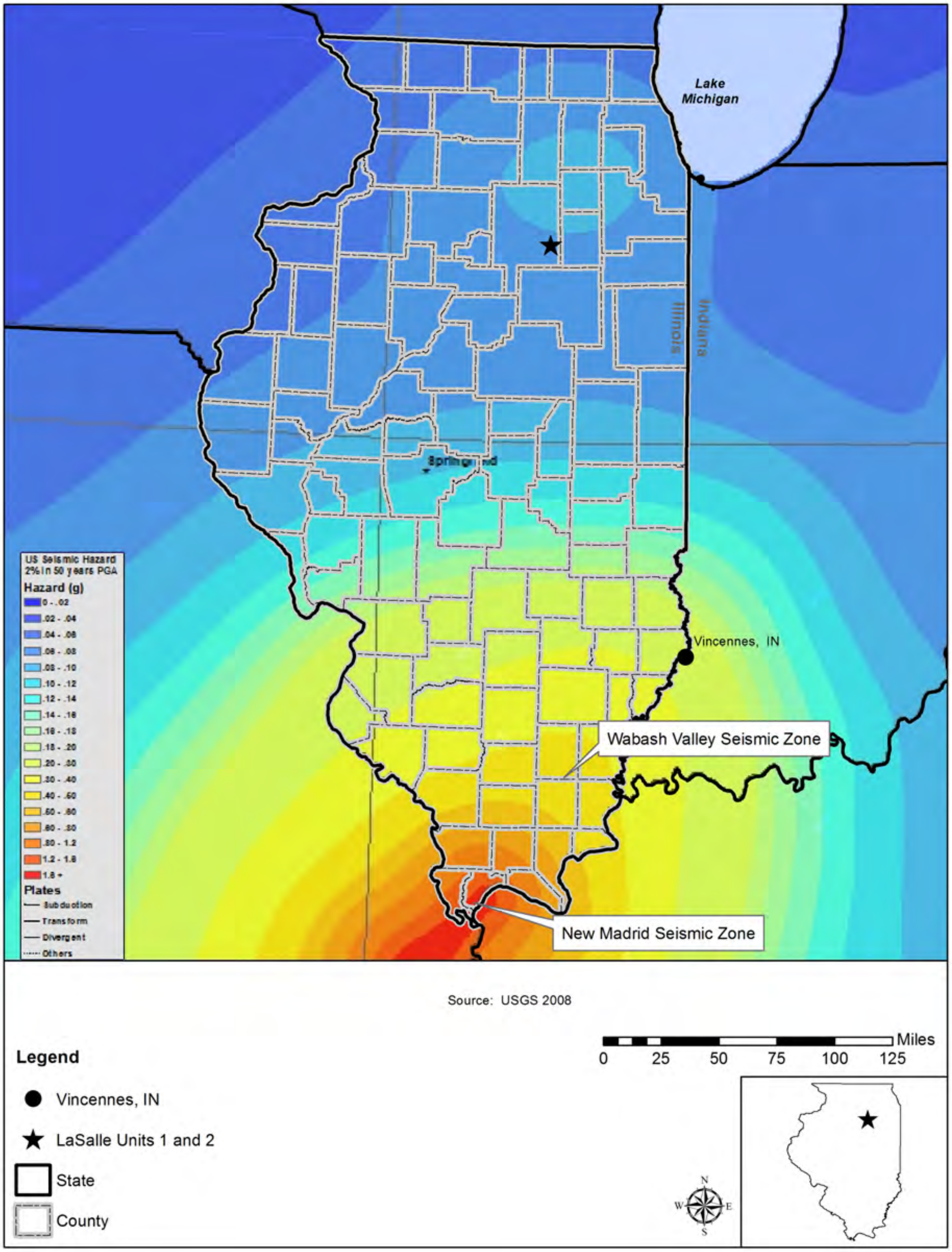

Figure 3.5-3 Seismic Hazard Map

There have been only four epicenters recorded in the last 200 years within the 80 km (50-mi) radius of the site (Figure 3.5-4). The largest and most recent of these was the 1972 event in Lee County (approximately 64 km [40 mi]) northwest of the site, which had magnitude of 4.0 on the Richter scale and a maximum intensity of VI (MM). The earthquake nearest the site (approximately 32 km [20 mi] northeast) occurred in 1912 with a magnitude 4.5 on the Richter scale and a maximum intensity of VI (MM) (Exelon Nuclear 2012a; USGS 2013a).

Safe Shutdown Earthquake

The probable northernmost extent of the large intensity New Madrid-type earthquakes has been studied extensively since the safe shutdown earthquake (SSE) for LSCS was calculated (Exelon Nuclear 2012a). Based on tectonic, geophysical, and seismic data, including evidence from an NRC-funded study of the New Madrid region, the New Madrid seismogenic region most likely does not extend north of the Rough Creek Fault Zone (Exelon Nuclear 2012a), which is located in western Kentucky and southeast Illinois.

As requested by the NRC for the LaSalle SSE, Exelon Generation evaluated the effect of a New Madrid 1811-1812 intensity earthquake occurring at Vincennes, Indiana, approximately 290 km (180 mi) from the site and estimated that a sustained maximum acceleration of 0.06 gravity (g) may be experienced at the site if a New Madrid-type event was centered at Vincennes. A 1976 Preliminary Safety Analysis Report for Marble Hill (an unfinished nuclear plant in Indiana) compared the spectra of a 0.2g regional earthquake with that of an earthquake 177 km (110 mi) distant which produced a 0.1g sustained maximum acceleration at the site. The results of the comparison were that the distant event did not govern the design of the Station. Therefore, a distant earthquake at Vincennes, with a sustained maximum acceleration of 0.06g at the site would not govern the LSCS design, because the acceleration due to the regional earthquake used for design purposes was 0.2g (Exelon Nuclear 2012a).

All earthquakes with intensities greater than VII (MM) in the region of the site, such as a 1909 earthquake that is reported as the largest earthquake in northern Illinois (Huysken, et al. 2008), can be correlated with peripheral geologic structures. Therefore, it is conceivable that earthquakes such as the earthquake of 1909 which had a magnitude of approximately 5.1 on the Richter scale and a maximum intensity of VII (MM) could occur in the site vicinity (Exelon Nuclear 2012a).

LSCS's SSE assumes the possibility of a nearby earthquake similar in type and intensity to the 1909 earthquake. Seismic Category I structures are designed for safe shutdown with maximum horizontal ground accelerations at the foundation level of 0.2g, and the corresponding maximum vertical ground acceleration is 2/3 of horizontal acceleration (Exelon Nuclear 2012a).

Seismic Hazards

As Figure 3.5-3 indicates, LSCS is in a region that has a 2 percent in 50 years (once in 2,500 years) probability of exceeding a peak ground acceleration between 0.06 and 0.08g (USGS undated-a).

No capable faults are known to exist within 322 km (200 mi) of the site (Crone, et al. 2000), and no earthquake epicenter has been reported within 8 km (5 mi) of the site (see Figure 3.5-4).

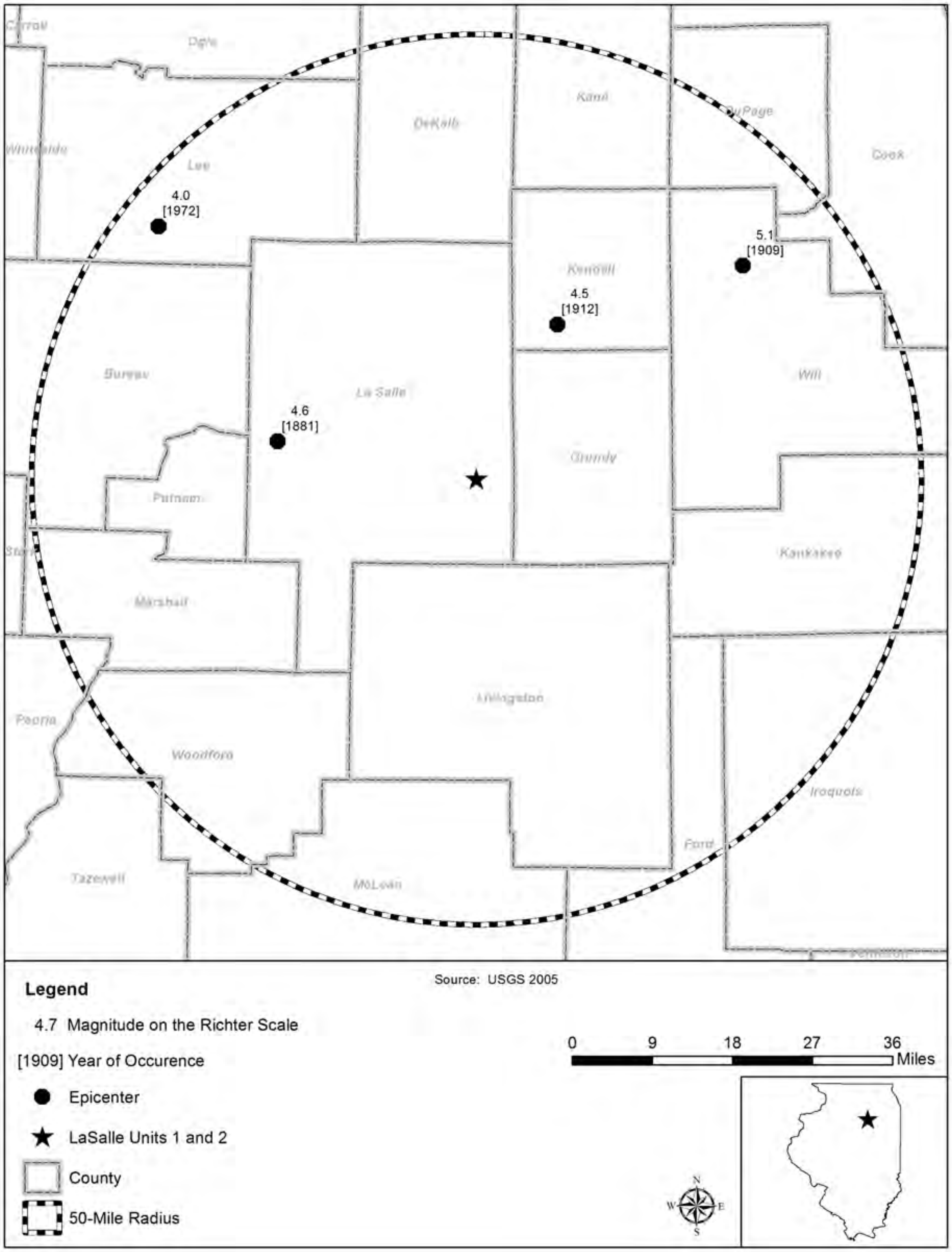

Figure 3.5-4 Earthquake Epicenters within 50 Miles of LSCS, 1568 to 2004

Table 3.5-1 Site Stratigraphic Units and Characteristics[a]

<table>
<tr><th>SYSTEM</th><th>SERIES</th><th>GROUP OR FORMATION</th><th colspan="2">HYDROGEOLOGIC UNIT</th><th>DESCRIPTION</th><th>HYDROGEOLOGIC CHARACTERISTICS[a]</th></tr>
<tr><td rowspan="7">Quaternary</td><td rowspan="7">Pleistocene</td><td>Cahokia Alluvium</td><td colspan="2" rowspan="4">Alluvial Aquifer</td><td rowspan="4">Silty clay or clayey silt underlain by silty sand, gravelly sand and sand/gravel mixtures</td><td rowspan="4">Groundwater occurs under water table conditions. The aquifer receives recharge primarily by direct infiltration of precipitation and by inflow from the Illinois River. Yields are adequate for domestic use owing to limited recharge, the thin saturated thickness, and the lateral discontinuity of the sand and gravel deposits.</td></tr>
<tr><td>Peyton Colluvium</td></tr>
<tr><td>Grayslake Peat</td></tr>
<tr><td>Henry Formation</td></tr>
<tr><td>Richland Loess</td><td colspan="2" rowspan="2">Glacial Drift Aquitard</td><td>Silty clay or clayey silt</td><td rowspan="2">Groundwater occurs predominantly in sand and gravel pockets within the glacial drift. Yields are quite variable and typically low, suitable only for domestic and farm purposes. Wells or cisterns that intersect the more permeable zones may exhibit high, short-term yields. The glacial drift aquitard locally overlies the buried bedrock valley aquifers.</td></tr>
<tr><td>Wedron Formation</td><td>Silty clay or clayey silt with interspersed sand and gravel, some thin sand and gravel pockets</td></tr>
<tr><td></td><td colspan="2">Buried Bedrock Valley Aquifers</td><td>Sand and gravel, some silt</td><td>The buried bedrock valley aquifers consist of sand and gravel deposited in channels cut into the underlying Pennsylvania strata. Groundwater occurs under water table conditions. Where the glaciofluvial deposits are clean and well-sorted, yields of 100 gpm or more can be sustained.</td></tr>
<tr><td rowspan="2">Pennsylvanian</td><td rowspan="2">Desmoinesian</td><td>Carbondale Formation</td><td colspan="2" rowspan="2">Pennsylvanian Aquitard</td><td rowspan="2">Principally shale, with come interbedded underclay, sandstone, limestone, and coal</td><td rowspan="2">Groundwater occurs primarily in thin sandstone beds and occasionally in joints in thin limestone beds. Groundwater occurs under leaky artesian conditions. The high proportion of shales makes the Pennsylvania strata generally unfavorable as aquifers. Yields are low and unsuitable only for domestic and farm purposes.</td></tr>
<tr><td>Spoon Formation</td></tr>
<tr><td rowspan="3">Ordovician</td><td rowspan="2">Champlainian</td><td>Platteville Group</td><td>Platteville dolomites</td><td rowspan="7">Cambrian-Ordovician Aquifer</td><td>Dolomite and limestone, locally cherty, sandy at base, shale partings.</td><td rowspan="7">Groundwater occurs under leaky artesian conditions in the sandstones and in joints in the dolomites. Yields are variable and depend upon which units are open to the well.

In terms of the total yield of a well penetrating the entire thickness of the Cambrian-Ordovician Aquifer, the Glenwood-St. Peter sandstone supplies about 15 percent, the Prairie du Chien, Potosi, and Franconia dolomites collectively supply about 35 percent, and the Ironton-Galesville sandstone supplies about 50 percent.</td></tr>
<tr><td>Ancell Group</td><td>Glenwood-St. Peter Sandstone</td><td>Sandstone, shale at top, little dolomite, locally cherty at base</td></tr>
<tr><td>Canadian</td><td>Prairie du Chien Group</td><td rowspan="3">Prairie du Chien, Potosi, and Franconia dolomites</td><td rowspan="3">Sandy dolomite, dolomitic sandstone, cherty at top, interbedded shale in lower part</td></tr>
<tr><td rowspan="6">Cambrian</td><td rowspan="6">Croixan</td><td>Potosi Dolomite</td></tr>
<tr><td>Franconia Formation</td></tr>
<tr><td>Ironton Sandstone</td><td rowspan="2">Ironton-Galesville Sandstone</td><td rowspan="2">Sandstone, upper part dolomite</td></tr>
<tr><td>Galesville Sandstone</td></tr>
<tr><td>Eau Claire Formation</td><td colspan="2">Eau Claire Aquitard (upper and middle beds)</td><td>Shales, dolomites, and shaly dolomitic sandstone</td><td>Insignificant amounts of groundwater may occur in joints. These beds act as a confining layer between the Cambrian-Ordovician Aquifer and the Mt. Simon Aquifer.</td></tr>
<tr><td>Mt. Simon Sandstone</td><td colspan="2">Mt. Simon Aquifer</td><td>Sandstone</td><td>Groundwater occurs under leaky artesian conditions. Groundwater in this aquifer is too highly mineralized for most purposes. Adequate supplies for municipal and industrial use are more easily obtained from shallower aquifers.</td></tr>
</table>

[a] Adapted from Exelon Nuclear 2012a

Table 3.5-2 Agricultural Soil Characterization Details

Map No.[1]	Soil Series	Landform	USDA Soil Texture Classification	Prime Farmland	Erosion Potential from Water
		Upland Soils			
91	Swygert	Ground moraines and end moraines	Silty Clay Loam	Yes	Low
228	Nappanee	Ground moraines and end moraines	Silt Loam	Yes	Moderate
235	Bryce	Ground moraines and glacial lakes	Silty Clay	Yes	Low
241	Chatsworth	Ground moraines and end moraines	Silty Clay	No	Moderate
320	Frankfort	Ground moraines and end moraines	Silt Loam	Yes	Moderate
375	Rutland	Ground moraines and lake moraines	Silty Clay Loam	Yes	Low
560	St. Clair	Ground moraines and end moraines	Silty Clay Loam	No	Moderate
		Valley Soils			
149	Brenton	Outwash plains and steam terraces	Silt Loam	Yes	Low
307	Ross	Flood plains	Loam	Yes	Low
303	Peotone	Ground moraines	Silty Clay Loam	No	Low
516	Faxon	Outwash plains and steam terraces	Loam	Yes	Moderate
802, 803, 804	Orthents	Leveled land, spoil piles, stream terraces	Loam	No	Low
817	Channahon-Hesch	Outwash plains, floodplain steps, and stream terraces	Fine Sandy Loams	No	Low
8404	Titus	Flood plains	Silty Clay Loam	Yes	Low

Source: USDA 2008
[1] See Figure 3.5-2

3.6 Water Resources

3.6.1 Surface Water Resources

LSCS is in the Illinois River basin, which is drained by the main stem of the Illinois River and its tributaries, including the canal system in the Chicago area. From its origin in Grundy County, the Illinois River flows west, then southwest, 439 km for (273 miles) before emptying into the Mississippi River near Grafton, Illinois. The Illinois River is the largest tributary of the Mississippi River above the Missouri River (Exelon Nuclear 2012a).

In the site vicinity, the river has a U-shaped cross-section, with a width and depth at normal pool of 244 m (800 ft) and 3.6 m (12 feet), respectively. The width of the river's floodplain nearest the site is 2.4 km (1.5 miles) (Exelon Nuclear 2012a). The LSCS plant floor is 57 m (188 ft) above a postulated probable maximum flood. For this reason, the LSCS UFSAR characterizes the Station as "flood proof" (Exelon Nuclear 2012a). The river screen house and the blowdown outfall structure are the only plant facilities that could be affected by river floods. The screen house is designed to withstand the 100-year flood (Exelon Nuclear 2012a).

The river screen house, from which makeup water is pumped to the cooling pond, described in Section 2.2.3, stands on the south shore of the Illinois River approximately 5.6 km (3.5 miles) north of the north dike of the cooling pond. The USGS maintains a permanent gaging station at Marseilles, IL, downstream of the LSCS river screen house and blowdown discharge. For water years 1920-2012, annual mean flow at Marseilles ranged from 158,093 to 505,456 L/sec (5,583 to 17,850 cubic feet per second [cfs]) and averaged 304,689 L/sec (10,760 cfs) (USGS 2013b). Daily mean flows over the same period ranged from 13,054 to 2,888,318 L/sec (461 to 102,000 cfs). Flows at the Marseilles gaging station are highest in the spring (March-May) and lowest in late summer and fall (August-October).

Locally, the South Kickapoo Creek discharges into the Illinois River from the south 500 m (1,800 ft) downstream of the river screen house. Other streams in the vicinity are Spring Brook, Deadly Run, Armstrong Run, and Hog Run. These streams discharge into the Illinois River from the south at 3.9 km (2.4 miles), 6 km (3.7 miles), 7.2 km (4.5 miles), and 7.7 km (4.8 miles) upstream of the river screen house, respectively. Figures 3.6-1 and 3.1-2 show the surface water bodies associated with Station operations and water bodies within a 10 km (6-mile) radius of the site, respectively.

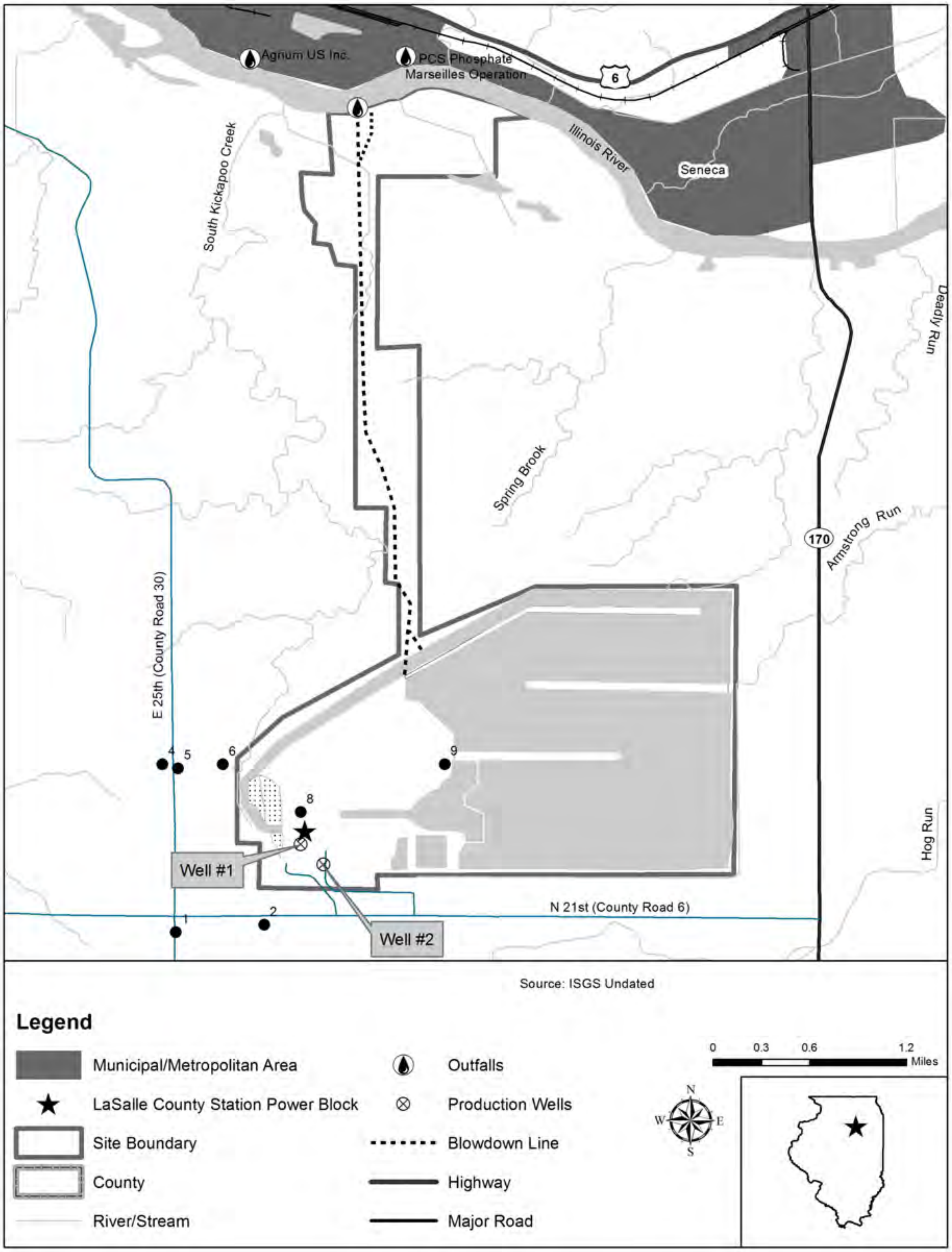

Figure 3.6-1 Surface Waters and Groundwater Well Locations at LSCS

3.6.2 Groundwater Resources

The Illinois EPA, in cooperation with the IDNR, has designated four state priority groundwater protection planning regions: the Northern Region, the Northeastern Region, the Central Region, and the Southern Region (IEPA Undated). LSCS does not fall within any of the priority groundwater protection regions.

The hydrogeologic systems at the site consist of (listed in order of descending depth):

- The Quaternary Alluvial Aquifer
- The Quaternary Glacial Drift Aquitard
- The Buried Bedrock Valley Aquifers
- The Pennsylvanian Aquitard
- The Cambrian-Ordovician Aquifer System

The hydrogeologic characteristics of these systems are summarized in Table 3.5-1 and discussed in the sections that follow.

<u>Quaternary Alluvial Aquifer</u>

The alluvial aquifer nearest LSCS is adjacent to the Illinois River. Although alluvial deposits are present on both sides of the river valley, the river functions as a hydrogeologic discharge boundary, thereby separating the alluvial aquifers on either side of the river from each other. The alluvial aquifer on the south side of the river extends along the river and is bounded on the north by the river and on the south by the valley walls. The width of the aquifer ranges from 183 m (600 ft) to 2,134 m (7,000 ft). The width of the aquifer in the vicinity of the river screen house ranges from 1,067 to 1,463 m (3,500 to 4,800 ft).

The aquifer occurs under water table conditions and receives recharge primarily by precipitation and inflow from the river during periods of high river flows. Yields from the alluvial aquifer at the site are not known, but are most likely adequate for domestic use only (Exelon Nuclear 2012a).

<u>Quaternary Glacial Drift Aquitard</u>

The Glacial Drift Aquitard underlies the upland portion of the site and consists of relatively impermeable clay tills with occasional discontinuous pockets of well-graded sand and gravel. Groundwater occurs in the aquitard primarily in the discontinuous sand and gravel pockets. The permeable zones within the aquitard are recharged by the slow infiltration of precipitation through the tills. Groundwater in the aquitard is lost by discharge to nearby stream valleys, the underlying bedrock, or the glaciofluvial buried bedrock valley aquifer, or by pumping through wells (Exelon Nuclear 2012a).

<u>Buried Bedrock Valley Aquifers</u>

As discussed in Section 3.5, the site is located over a saddle in the bedrock topography that functions as a drainage divide between two buried bedrock valley aquifers consisting of silty sand with some gravel and occasional pockets of silt, clayey silt or silty clay. The buried bedrock valley aquifers are recharged slowly by infiltration of precipitation through the thick overlying tills. The potential for groundwater development from the buried bedrock valley aquifers is limited by slow recharge rates. Wells in the buried bedrock valley aquifers near the site are used only for domestic or farm purposes (Exelon Nuclear 2012a).

Pennsylvanian Aquitard

The Pennsylvanian Aquitard consists of alternating beds of shale, siltstone, underclay, sandstone, limestone, coal, and many gradational layers. Relatively impermeable shale and siltstone comprise more than 90 percent of the aquitard. Groundwater in the aquitard occurs under artesian conditions. Wells finished in the aquitard get water primarily from the thin sandstone and limestone beds that are recharged by seepage through the overlying shales and glacial drift. In general, the aquitard supplies less than 0.63 L/sec (10 gpm), which is a yield suitable only for domestic or farm use (Exelon Nuclear 2012a).

Cambrian-Ordovician Aquifer System

The most important aquifer in the region is the Cambrian-Ordovician Aquifer. At LSCS the aquifer is composed of the following strata (in descending depth order):

- Ordovician-aged Platteville Group
- Ordovician-aged Ancell Aquifer (Glenwood – St. Peter Sandstone)
- Cambrian-aged Potosi Dolomite, Franconia Formation, Ironton-Galesville Sandstone

The Cambrian-Ordovician Aquifer system underlying the site averages approximately 290 m (950 ft) thick. Although numerous alternating layers of sandstones, limestone, and dolomites impart a heterogeneous character to the system, these units are hydraulically connected and behave as a single aquifer (Visocky, et al. 1985).

Groundwater Flow

As shown in Figure 3.6-2, the shallow groundwater in the Wedron Clay Till under the site flows generally to the southwest with an apparent low point southwest of the turbine building. The only subsurface features that appear to be able to affect groundwater flow are the foundations of the turbine and reactor buildings. Schematic diagrams in the UFSAR show that the

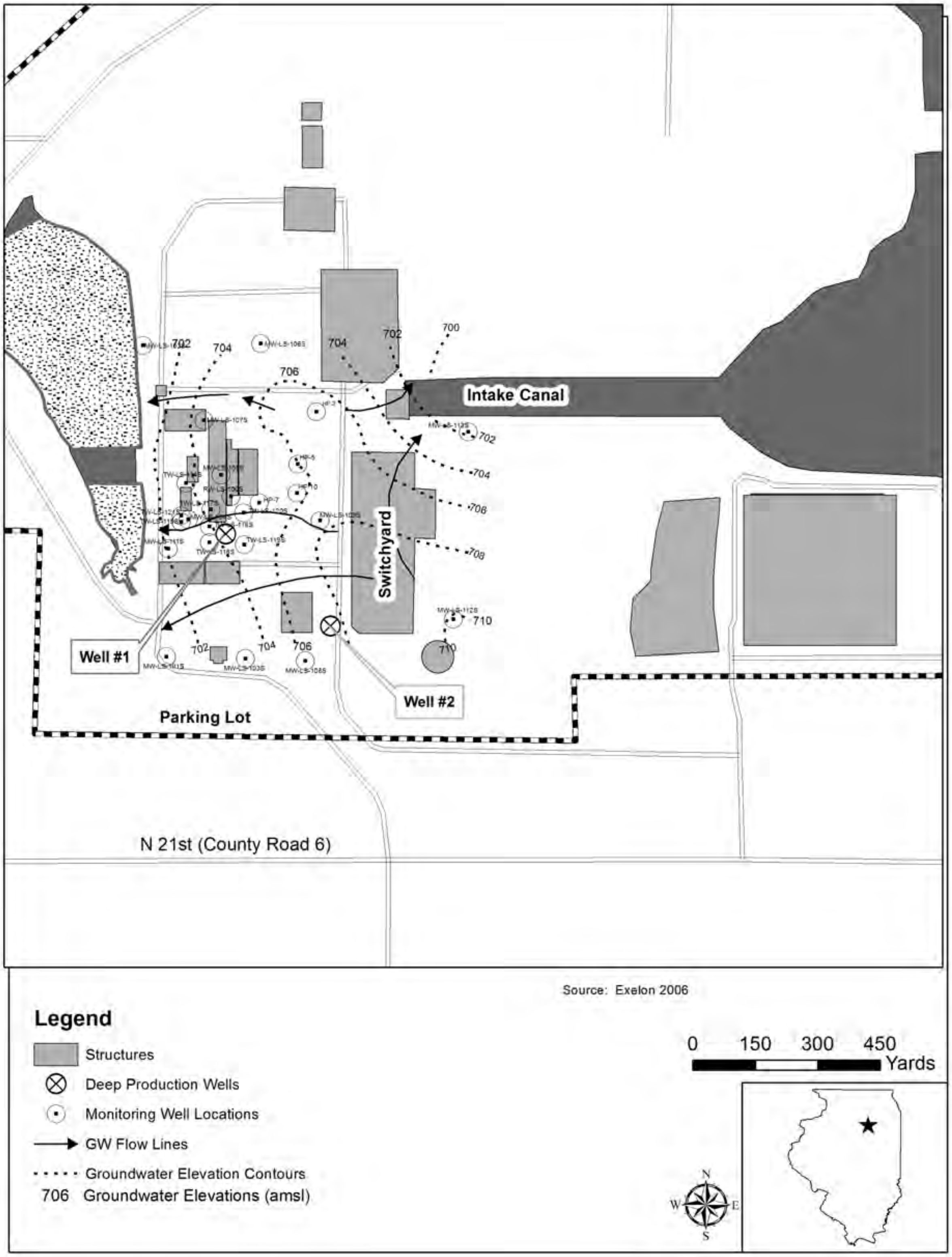

Figure 3.6-2 Groundwater Flow Map

foundation of the turbine and reactor buildings are approximately 18 m (60 ft) below ground surface (bgs), in the Wedron Clay Till (Exelon Nuclear 2012a). Therefore, shallow groundwater flow from the northeast portion of the site is diverted north and south around the building's foundations as it flows toward the west.

The elevation of the top of the Wedron Clay Till beneath the protected area is approximately 0.3 to 3.6 m (1 to 12 feet) lower than the elevation of the top of the clay at the protected area perimeter, indicating that a depressed area in the natural clay exists beneath the protected area. Groundwater accumulates in this "bowl" under the protected area until it fills the bowl. During wet conditions, groundwater flows into the bowl from the northeast, filling the depression. As groundwater continues to flow into the depressed area of the Wedron Clay Till beneath the site, eventually the depression fills up and overflows to the west and southwest. During dry conditions, groundwater that flowed into the depression would be trapped, effectively isolating that groundwater from the local flow regime outside of the influence of the depression (CRA 2006). Depth to the shallow groundwater ranges from 0.6 to 2.3 m (2 to 7.5 ft) below ground surface (CRA 2006).

Groundwater flow in the Cambrian-Ordovician Aquifer in the area is to the northeast in response to regional pumping centers near Joliet, Illinois (Burch 2008).

Seepage from the cooling pond is negligible because the pond was excavated almost entirely in Wedron silty clay till, which is 36.6 to 42.7 m (120 to 140 ft; Exelon Nuclear 2012a) thick and relatively impermeable. The two-dimensional computer model SEEPAGE was used to estimate the rate of seepage through the dike and underlying subsoil. The permeability of the materials was determined from tests performed on undisturbed and remolded samples of Wedron silty clay till from test borings and pits in the reservoir area. The model indicated that the rate of seepage through the dike and the base would total 3.8 L (1 gal) per day or 1.5×10^{-6} cfs per foot of dike (Exelon Nuclear 2012a).

LSCS has no active dewatering system or program for removal of groundwater in-leakage into plant structures. Historically, such in-leakage has been small and not quantified. Liquids from floor drains and sumps throughout the plant are routed based on origin to the radwaste treatment system or the wastewater treatment plant, which are described in Sections 2.2.7 and 2.2.8, respectively.

3.6.3 Surface Water Use

3.6.3.1 Offsite Surface Water Use

The Illinois State Water Survey's Illinois Water Inventory Program Database has records for two commercial/industrial water intakes (in addition to the LSCS intake) on the Marseilles Pool of the Illinois River (ISWS 2013). The Marseilles Pool is the reach of the Illinois River that is impounded by the Marseilles Lock and Dam. It extends from the Marseilles Lock and Dam at near Marseilles, Illinois, upstream to the Dresden Lock and Dam south of Channahon, Illinois.

The other intakes (Figure 3.6-1), belong to Agrium U.S., Inc. (ISWS Facility ID: 09934335) and PCE Phosphate – Marseilles Operation (ISWS Facility ID: 09934330). The volume of river water used by these two facilities is unknown because water use data for commercial-industrial facilities are protected as trade secrets, even from a FOIA request (Byrant 2013).

3.6.3.2 Plant Surface Water Use

As discussed in Section 2.2, makeup water is pumped from the Illinois River to the cooling pond to replace losses due to evaporation, blowdown, and seepage. The makeup pumps have a total capacity of 114,000 L/min (30,000 gpm) (Exelon Nuclear 2012a). The rate of pumping varies depending on the plant operations and weather conditions (Exelon Nuclear 2012a).

Blowdown is released from the cooling pond to prevent the buildup of dissolved solids. The maximum blowdown flow rate is 341,000 L/min (90,000 gpm), but valve settings limit normal blowdown flow to 220,000 L/min (58,000 gpm) or less, with a target annual average of 114,000 L/min (30,000 gpm). Blowdown rates averaged 95,145 L/min (56 cfs; 25,269 gpm) over a recent five-year period (Table 3.6-1).

As summarized in Table 3.6-1, LSCS's average surface water consumptive use (average makeup water volume withdrawn minus average water volume returned to river as blowdown) for water years 2008 through 2012 was 81,193 L/min (48 cfs; 21,449 gpm). The Illinois River's 92-year (1920 – 2012) annual average mean flow at Marseilles is 1.8×10^7 L/min (10,760 cfs; 4.8×10^6 gpm; USGS 2013b). Therefore, LSCS's average consumptive water use for the five-year period 2008 through 2012 at 100 percent load, represents less than 0.5 percent of the river's 92-year annual average mean flow.

In Illinois, there is no general permitting system for surface water withdrawals. Illinois follows the Riparian Doctrine of Reasonable Use: ownership of land next to a stream entitles the owner to the reasonable use of the stream's water provided that such use doesn't interfere with the reasonable use by others with riparian rights (IDOT 1985).

LSCS does not have IDNR-established limits on withdrawals of makeup water from the Illinois River (Buinickas 2013).

3.6.4 Groundwater Use

3.6.4.1 Offsite Groundwater Use

All public groundwater users within 16 km (10 mi) of the site are listed in Table 3.6-2. Most of the groundwater is obtained from wells in the Cambrian-Ordovician Aquifer. Water supplies for Seneca, Kinsman, Marseilles, and Illini State Park are taken entirely from this aquifer. Ransom withdraws groundwater from both the Cambrian-Ordovician Aquifer and the more permeable zones in the Pennsylvanian Aquitard. Grand Ridge is the only municipality within 16 km (10 mi) to get water from the glaciofluvial deposits of the Buried Bedrock Valley Aquifers. Table 3.6-2 provides the available data on wells in each public system and the average consumption from each system. The other small communities within 16 km (10 mi) are not served by public water supplies. Residents in these communities and the surrounding rural areas obtain groundwater from individual wells in the glacial drift, the Pennsylvanian strata, or the upper portion of the Cambrian-Ordovician Aquifer (Exelon Nuclear 2012a).

Apart from the groundwater supply wells for LSCS, there are no public water supply wells screened in the Ironton-Galesville aquifer within 8 km (5 mi) of the site. The closest public well to the site that is screened in the Ironton-Galesville aquifer is one of the five production wells used by Marseilles. The well is approximately 10 km (6 mi) northwest of the site and is installed to a depth of 447 m (1,466 ft) bgs. The well pumps an average of 3,217 L/sec (850 gpm) (Exelon Nuclear 2012a).

Domestic water supplies are most commonly from either the sand and gravel zones within the glacial drift or the sandstone and limestone beds of the Pennsylvanian Aquitard. Wells in these strata usually yield enough water for domestic or low-demand farm purposes. Five domestic ells are located within 1.5 km (1 mi) of the Station (labeled 1, 2, 4, 6 and 9 on Figure 3.6-1).

The wells range in depth from 57 to 165 m (187 to 540 ft) bgs (Table 3.6-3). Wells 6 and 9 were installed in 1916 and there is no information about their current condition (ISGS Undated).

In 2006, a drinking water well survey was conducted in the vicinity of the plant. No residents in the vicinity use the shallow water aquifer as a drinking water supply. The results of the survey and hydrological studies of aquifer flow and permeation rates from the shallow aquifer to the deep aquifer at the site determined that there is no pathway from shallow groundwater to receptor (Exelon Generation 2013c)

3.6.4.2 Plant Groundwater Use

In 1972 and 1974, two groundwater wells (Wells #1 and #2) were installed into the Cambrian-Ordovician Ironton-Galesville Sandstone Aquifer. Well #1 (ISGS API 120992245100) was installed in 1974 to a depth of 497 m (1,629 ft) bgs. Well #2 (ISGS API 120990234900) was installed in 1972 to a depth of 494 m (1,620 ft) bgs (ISGS Undated). For water years 2008 through 2012, Well #1 pumped an average 1.3 L/sec (20.8 gpm), and Well #2 pumped an average 0.33 L/sec (5.3 gpm) for a total groundwater withdrawal rate of 1.6 L/sec (26.1 gpm) (Exelon Generation 2008a, Generation 2009, Exelon Generation 2010a, Exelon Generation 2011a, Exelon Generation 2012a).

Illinois has no general permitting system for groundwater withdrawal. However, wells located on a parcel of property where the total rate of withdrawal of all wells exceeds 263 L/min or 378,541 L/day (70 gpm or 100,000 gallons per day) are defined as high-capacity wells and must file annual reports of their withdrawals to the Illinois State Water Survey. Since January 1, 2010, an entity installing any high-capacity well has been required to notify the Illinois Department of Agriculture's designated Soil and Water Conservation District before construction of the well begins)525 ILCS 45/, Water Use Act of 1983, as amended by Public Act 096-0222; effective 1/1/2010). Based on the LSCS groundwater pumping rate, its water-supply wells are not high-capacity wells (525 ILCS 45/ Water Use Act of 1983, as amended by Public Act 096-0222; effective 1/1/2010; NCSL 2013) therefore the LSCS groundwater withdrawal rate does not meet this criterion for registration.

3.6.5 Surface Water Quality

3.6.5.1 Regional Surface Water Quality

The decline of the Illinois River's water quality and ecological communities in the 19th and 20th centuries has been chronicled by Talkington (Talkington 1991), in an educational website ("Of Time and the River") devoted to the Illinois River (ISM Undated), and elsewhere. Water quality was degraded by rapid population growth in the region (untreated and inadequately treated sewage), the development and expansion of industry (industrial pollutants), the conversion of undeveloped prairie and forestland into cropland (agricultural chemicals runoff and sedimentation), and alteration of the historical flow regimes in the river and its tributaries (navigation and flood control projects).

However, passage of the 1970 Illinois Environmental Protection Act and the 1972 Federal Water Pollution Control Act Amendments (now referred to as the Clean Water Act) imposed strict water quality standards on point-source dischargers. This compelled municipal and industrial dischargers to improve and modernize wastewater treatment facilities and marked the point at which water quality in the basin began to improve. Talkington (Talkington 1991) observed that "the waters of the Illinois (River), as well as sediments, all showed considerable improvement between 1972 and 1979." Concentrations of total suspended solids and harmful substances such as dissolved barium, manganese, and boron all declined on the upper Illinois and Des Plaines Rivers between 1977 and 1989 (Talkington 1991). Talkington observed that "1990 figures showed that only a small portion of the Illinois Waterway remains in 'poor' condition." Improved wastewater treatment, which came about as a result of enactment of the Illinois Environmental Protection Act and the Clean Water Act, dramatically lowered levels of ammonia-nitrogen and organic pollutants in the Illinois River. Decomposition of either consumes oxygen, with potentially devastating effects on aquatic life.

The USGS conducted a comprehensive assessment of water quality in the upper Illinois Basin as part of its National Water Quality Assessment (NAWQA) Program. The assessment was guided by pilot studies conducted by USGS from 1987 through 1991 and used data collected by Illinois between 1978 and 1997 to evaluate water quality trends. From 1999 through 2001, the assessment focused again on the studies in the basin conducted by USGS. The goal of the assessment was to provide resource and planning agencies with information "useful for guiding water-management and protection strategies" (USGS 2004).

Sullivan (Sullivan 2000) conducted an investigation of nutrients and suspended solids in the Upper Illinois River basin between 1978 and 1997 in support of the NAWQA Program, using data supplied by IEPA. Concentrations of ammonia-nitrogen, nitrate, total phosphorus, and ortho-phosphate at the Marseilles monitoring station, downstream of the LSCS intake and discharge, were among the highest measured in the Mississippi River basin, reflecting municipal inputs of nutrients from the Chicago area and agricultural inputs from tributary streams throughout the basin. Sullivan (Sullivan 2000) listed probable sources of nutrients as wastewater treatment plant effluent (total nitrogen, total phosphorus), fertilizer runoff from agricultural lands (total nitrogen, total phosphorus), urban runoff (total nitrogen, total phosphorus), and precipitation (ammonia, nitrite + nitrate). Other, less-important sources were groundwater, water diverted from Lake Michigan, and decomposing plant material (e.g., leaf litter) in tributary streams.

With respect to water quality trends between 1978 and 1997, Sullivan (Sullivan 2000) reported a statistically significant ($p<0.005$) decrease in ammonia concentrations at Marseilles and most other monitoring stations, along with a corresponding increase in nitrate concentrations. This was attributed to improved wastewater treatment in the basin. In modern sewage treatment plants, ammonia is biologically oxidized into nitrite, then nitrate, making the sewage treatment plant effluent less toxic to fish and other aquatic organisms. No other statistically significant trends were observed for nutrients at the Marseilles monitoring station.

In addition to nutrients and chemicals that create biological and chemical oxygen demand, the Upper Illinois Basin NAWQA Program examined the nature and extent of organic chemicals such as pesticides and herbicides. The study revealed that insecticides were present more often, and at higher concentrations, in urban parts of the Illinois River basin. Diazinon, widely used to control cockroaches, ants, and fleas, was detected (concentrations ≥ 0.05 micrograms per liter [µg/L]) in all streams draining urban areas of the basin but was not detected in streams draining agricultural areas (USGS 2004). Concentrations of organochlorine pesticides (e.g., DDT) and polychlorinated biphenyls (PCBs) were elevated in sediments of some Illinois River tributary streams in the Chicago area, but generally decreased with distance downstream from Chicago. PCBs in common carp from the Illinois River, however, ranged from 4,400 µg/L at Marseilles to 190 µg/L at Hardin, near the river's confluence with the Mississippi River (USGS 2004). Malathion, an organophosphate pesticide widely used to control mosquitoes and garden pests was not detected in the Illinois River basin in 2000-2001, presumably because its use had declined.

While insecticides were associated with urban areas, herbicides were detected more often and at higher concentrations in streams draining agricultural areas. Atrazine --- widely used to control corn and soybean pests --- was detected in every sample taken from Illinois River basin streams draining agricultural watersheds. Other herbicides commonly detected in these streams were metolachlor, acetochlor, and cyanazine (USGS 2004). However, concentrations of some of these compounds (e.g., metolachlor and cyanazine) decreased from 1991 to 2001, either because of changes in EPA regulations or because more effective chemicals had become available. Acetochlor and glyophosphate (often sold as Roundup or Rodeo) appear to be gaining in popularity as use of other chemicals decreases.

The stream segment (IL-D-23) of the Illinois River receiving blowdown from LSCS is identified as impaired for fish consumption and primary contact due to mercury, PCBs, and fecal coliform (IEPA 2014a). These pollutants are attributed to atmospheric deposition or "unknown sources." Releases of PCBs and complex metal-bearing waste streams are prohibited by NPDES Permit IL0048321.

3.6.5.2 Radiological Releases to Surface Water

Radiological Environmental Monitoring Program (REMP)

NRC requires all nuclear power reactor licensees to demonstrate compliance with regulations limiting radiation doses to members of the public and mandating that radioactive releases contributing to such doses be as low as reasonably achievable (ALARA) (10 CFR Parts 20 and 50 and 40 CFR Part 190). In addition, 40 CFR Part 141 imposes limits on the concentrations of radionuclides, including tritium, in drinking water provided by public water supply systems. To meet these requirements, each nuclear power plant site has in place a Radiological Environmental Monitoring Program (REMP) specifying sampling frequency of environmental media, and reporting requirements. As part of the LSCS REMP, Exelon Generation analyzes the concentrations of certain radionuclides, including tritium, in the Illinois River above and below the LSCS blowdown discharge. Results are reported in the Annual Radiological Environmental Operating Report, which also covers the Meteorological Monitoring Program and Radiological Groundwater Protection Program.

Releases to Surface Water

LSCS operates liquid radioactive waste systems using a voluntary approach that limits the release of radioactive species via the liquid pathway. As a result, radioactively-contaminated liquid discharges do not normally occur. Notwithstanding, if treated waste water is not needed for recycle into main plant systems, such releases are authorized to the Illinois River and may occur through the cooling pond blowdown line. If a release were necessary, the waste waters would first be collected in a batch and would be sampled, analyzed and processed before discharge to ensure compliance with NRC regulations (see Section 2.2.7.1). The radionuclide concentrations in any batch that may be released to the river and resulting radiation doses would be well below regulatory limits.

As Section 3.6.6.2 indicates, tritium has been detected in onsite monitoring wells within the property boundary of the LSCS plant, and following a leak in 2010 from the Unit 1 recycled condensate tank, elevated tritium concentrations were observed. In response, additional groundwater monitoring wells were installed, and a remediation strategy was adopted of allowing natural migration of the tritium into an onsite storm water pond, which communicates with the cooling pond, ultimately blowing down to the Illinois River. In 2012, LSCS commenced low-flow-rate pumping of groundwater into the station's storm drain system to aid the remediation from natural migration. The continuous low flow pumping allows for a more controlled remediation of the plume than that of random natural migration. The flow is directed through on site storm drains to the same storm water pond that receives natural groundwater flow. Low flow rates are maintained to ensure that tritium concentrations remain below detectable levels at the release point to the Illinois River.

Illinois River tritium concentrations in weekly samples collected at Seneca, above the LSCS discharge, between 2008 and 2012, ranged from <200 pCi/L to 1,050 $\pm$ 169 pCi/L. Below the LaSalle discharge between 2008 and 2012, tritium concentrations ranged from <200 pCi/L to 1,150 + 178 pCi/L (Exelon Generation 2009; Exelon Generation 2010b; Exelon Generation 2011b Exelon Generation 2012c; Exelon Generation 2013c). Tritium concentrations in the Illinois River in 2010, 2011, and 2012 were consistent with previous years' concentrations. The EPA drinking water standard is 20,000 pCi/L.

3.6.5.3 Local, State, and Federal Permit Requirements

LSCS's discharges to the Illinois River (other than radiological, which are regulated by the NRC) are regulated through a National Pollutant Discharge Elimination System (NPDES) permit IL0048151, issued by the Illinois Environmental Protection Agency (IEPA). Discharges from LSCS are subject to the effluent limits and conditions specified in this permit, which may be renewed or modified from time to time.

Section 402(b) of the Clean Water Act (CWA) provides that the Governor of any state can apply to the Administrator of the EPA to administer the NPDES Program in the State. On October 23, 1977, the Illinois State NPDES Permit Program was approved by the EPA, giving Illinois authorization to implement the NPDES permitting program. The current NPDES permit for LSCS (Appendix C) was issued July 5, 2013 with an effective date of August 1, 2013, and has an expiration date of July 31, 2018.

In accordance with CWA Section 401 and Illinois EPA guidance, by letter dated February 4, 2014 (see Appendix B), Exelon Generation filed with Illinois EPA, IDNR, and the U.S. Army Corps of Engineers, an application for certification that issuance by NRC of renewed licenses for LaSalle County Station Units 1 and 2 will comply with Illinois state water quality standards. Determination by Illinois EPA of the application's completeness and initiation of the agency's technical review are expected to occur upon Exelon Generation's filing with the NRC of the LaSalle Station Units 1 and 2 License Renewal Application. Responses from the IDNR and U.S. Army Corps of Engineers (see Appendix B) indicate that permits from these agencies are not required to support renewal of the LSCS NRC operating licenses, and neither agency objected to issuance of the requested CWA Section 401 certification. Storm water runoff controls at the plant are described in the plant's Storm Water Pollution Prevention Plan (SWPPP) (Exelon Nuclear 2011a).

Exelon Generation may occasionally perform maintenance dredging at the river screen house forebay. The need for maintenance dredging is periodically evaluated under a dredging procedure that addresses the decision-making process for initiation of the dredging and prompts the responsible employees to perform dredging operations in accordance with Dredging Permit requirements (Department of Army Permit Number CEMVR-OD-P-2006).

3.6.5.4 2006 Hydrogeologic Investigation

In 2006, Exelon conducted a hydrogeologic investigation at LSCS as part of a fleet-wide effort to determine whether surface water or groundwater at its nuclear power generating facilities were being adversely impacted by releases of radionuclides within the protected areas. This initiative, which was conducted in accordance with the Nuclear Energy Institute (NEI) Industry Groundwater Protection Initiative - Final Guidance Document (NEI 07-07 [Final] August 2007), included an investigation at each Exelon Generation nuclear facility, including LSCS. As part of the LSCS investigation, six surface water samples were collected from the following surface water features: the north and south storm water ponds, the intake and discharge canals, and the Illinois River immediately upstream and downstream of the blowdown discharge location.

Tritium was detected in two of the four onsite surface water samples: in the north storm water pond at a concentration of 232 pCi/L, and in the intake canal at a concentration of 219 pCi/L. Tritium in both samples was below the EPA drinking water standard of 20,000 pCi/L (CRA 2006).

Tritium was not detected in the two Illinois River water samples (CRA 2006).

3.6.6 Groundwater Quality

3.6.6.1 Offsite Groundwater Quality

Concentrations of naturally-occurring radioactive isotopes in excess of the EPA drinking water standard have been detected in public supply groundwater taken from the Cambrian-Ordovician Aquifer. Radium-226 and radium-228 data from public water supply systems obtained during the 1980s and data obtained by the USGS in 1999 were used to estimate the extent of elevated radium in aquifers used for public supply in northern Illinois. With a few exceptions, radium concentrations in water from public supplies in northern Illinois exceeded the EPA primary drinking water standard of 5 pCi/L only in the Cambrian-Ordovician and Mt. Simon aquifers. The area where elevated radium concentrations were observed is in northern Illinois, and includes Kankakee, Livingston, Woodford, Tazewell, Fulton, McDonough, and Hancock Counties. Combined radium concentrations in the Cambrian-Ordovician St. Peter Sandstone were typically greater than 10 pCi/L, and exceeded 20 pCi/L in the far southwestern part of the area (USGS Undated).

The elevated concentrations of naturally-occurring radium-226 in the deep aquifer groundwater appear to be related to the accumulation of its parent elements, particularly uranium-238 and -234, and thorium-230 in the sandstone units (USGS Undated).

As part of the 2006 Hydrologic Investigation, drinking water samples were taken from the following communities' public water supply water wells: Marseilles, Seneca, Ransom, Ottawa, and Illini State Park. The samples were analyzed for gross beta, gamma isotopic, radioactive strontium, and tritium. Tritium concentrations were variable, ranging from <200 pCi/L to 350 pCi/L. Gross beta analytical results in the samples ranged from less than the lower limit of detection (LLD) of 1.6 pCi/L to 22 pCi/L (CRA 2006).

3.6.6.2 Plant Groundwater Quality

Radiological Environmental Monitoring Program (REMP)

In accordance with LSCS's REMP, Exelon Generation monitors for tritium and specific gamma-emitting radionuclides at two water supply wells at or near the plant: the onsite LSCS Well #1 (labeled as L-27 in the REMP report), and the Marseilles Wells 4, 5, and 6 (labeled as L-28-W4, L-28-W5, and L-28-W6, in the REMP report). Two control wells are also sampled.

During 2012, neither gamma-emitting radionuclides that may be produced by LSCS operations nor tritium were detected in groundwater samples above their respective LLD, which is consistent with previous years (Exelon Generation 2013c).

History of Tritium Releases

1985 HPCS Cycled Condensate Line Break

In 1985, the High Pressure Core Spray (HPCS) Cycled Condensate line broke in the area east-southeast of the reactor building. Four monitoring wells (HP-2, HP-5, HP-7, and HP-10) were installed and monthly groundwater samples were analyzed for tritium between January 1986 and September 1987. The highest detected tritium concentration in the monitoring wells was approximately 11,000 pCi/L in 1986 (CRA 2006). Tritium concentrations were as high as 148,000 pCi/L in a drawdown borehole installed near well HP-7 to manage groundwater while repairing the broken line. During the last 1987 sampling event, tritium was detected in one well at a concentration of 490 pCi/L, and not detected in the other three wells. These monitoring wells were sampled again as part of the 2006 Hydrogeologic Investigation and are included in the Radiological Groundwater Protection Program described below and in Section 4.5.2. In 2012, tritium was not detected above the LLD (200 pCi/L) in any of the wells associated with the 1985 leak (Exelon Generation 2013c).

2001 U2 Recycled Condensate Storage (CY) Tank Overflow

In September 2001, the roof of the Unit 2 Recycled Condensate Storage Tank was breached following a manual scram of Unit 2. The spill was evaluated for several isotopes, however not for tritium. In 2006 tritium concentrations were detected in monitoring well MW-LS-105S at concentrations from 1,280 $\pm$ 184 pCi/L to 766 $\pm$ 153 pCi/L (CRA 2006). The source of this tritium has been deemed most likely to be the release from the U2 CY storage tank overflow (CRA 2006).

2006 Blowdown Line Investigation

In 2006, water samples were collected and analyzed for tritium from 16 of the 17 vacuum breakers that had standing water along the blowdown line. One sample had a tritium concentration of 274 ± 129 pCi/L; in all other vacuum breakers tritium was not detected in concentrations above the LLD of 200 pCi/L. The sample with detectable tritium was re-analyzed using the distillation process which resulted in a revised tritium concentration estimate of less than the LLD of 200 pCi/L (CRA 2006).

2010 U1 Recycled Condensate (CY) Tank Leak

In 2010, a leak from the Unit 1 Recycled Condensate tank was identified and remediated. The issue was documented in the Corrective Actions Program and the proper reports and notifications were made to regulatory agencies and stakeholders. After isolating the leaking tank, it was drained, repaired, and returned to service. Remediation activities included the installation of monitoring wells TW-LS-114S through TW-LS-119S, increased groundwater sampling frequency, and using natural monitored attenuation to lower the tritium concentrations over time (Exelon Generation 2011b).

Two additional monitoring wells (TW-LS-120S and TW-LS-121S) were installed in June 2012 to further evaluate the tritium plume in the area of the tank (Exelon Generation 2013c). Because the tritium plume was dispersing with groundwater flow toward the property boundary, an extraction well (RW-LS-100S) was installed near the tank to impede the migration of the plume and allow time for the natural monitored attenuation to effectively diminish the tritium concentration. The well became operational in October, 2012.

In April of 2014, a second recovery well in the form of a French drain (RW-LS-101S) was installed to increase the recovery rate of the tritium plume. Both recovery wells discharge via the storm drain system to the south storm water pond. To date, no tritium has been detected offsite, and tritium migration offsite is not expected. Also no tritium has been detected in the cooling pond blowdown discharge to the Illinois River. Recovery of this tritium plume continues. The RGPP section, below, discusses the 2013 tritium concentrations in groundwater associated with this leak.

2006 Hydrogeologic Investigation

As described in the Nuclear Energy Institute (NEI) Industry Groundwater Protection Initiative -Final Guidance Document (NEI 2007), groundwater protection programs at nuclear generating facilities were required to be in place by July 31, 2006. Therefore, in conjunction with the effort described earlier for surface water, Exelon Generation initiated a fleet-wide effort in 2006 to determine whether groundwater associated with the protected areas of its nuclear power generating facilities was being adversely impacted by releases of radionuclides from within the protected areas. This effort included a hydrogeologic investigation at each Exelon Generation facility, including LSCS. One objective of the investigation was to evaluate groundwater quality at the facility, including the vertical and horizontal extent, quantity, concentrations, and potential sources of tritium and other radionuclides that might be present.

Thirteen new monitoring wells (MW-LS-101S through MW-LS-113S) were installed (Figure 3.6-2) and sampled for tritium, strontium-89, strontium-90, and gamma-emitting radionuclides. Groundwater levels were also measured in both the new and existing wells.

Gamma-emitting radionuclides and strontium-89/-90 were not detected at concentrations greater than their respective LLDs in any of the groundwater samples analyzed, but tritium was detected in monitoring well MW-LS-105S at a concentration of 1,280 ± 184 pCi/L (CRA 2006). The source of the tritium has been deemed most likely to be the 2001 release associated with a recycled condensate storage tank overflow described above (Exelon Generation 2013c). Samples from adjacent monitoring wells and surface water locations detected no tritium concentrations above the LLD.

Radiological Groundwater Protection Program (RGPP)

As described above, Exelon Generation established a Radiological Groundwater Protection Program at all its nuclear facilities in 2006 to meet the objectives of the Nuclear Energy Institutes' Industry Groundwater Protection Initiative. The RGPP enhances detection, management and communication of inadvertent radiological releases into groundwater that are below federal standards. The RGPP sampling program at each Station is independent of the Station's Radiological Environmental Monitoring Program, described in Section 3.6.5.2, which focuses on exposure pathways and radionuclides that lead to the highest potential radiation exposure to the public from Station operations. However, annual results of the RGPP sampling program at each Station are included as an appendix in the Station's Annual Radiological Environmental Operating Report, which has the primary purpose of presenting REMP and Meteorological Monitoring Program results to the NRC.

LSCS's sampling program for implementing the Exelon Generation RGPP includes 26 groundwater sampling wells. The well locations are shown on Figure 3.6-2. The wells sampled and the number of sampling events for each well may vary from year to year based on evaluation of sampling results in accordance with RGPP implementing procedures. Tables 4.5-1 and 4.5-2 describe the characteristics of the LSCS RGPP wells.

The Annual RGPP Report for 2012 (Exelon Generation 2013c) discusses the results of groundwater radionuclide monitoring from January 1 through December 31, 2012. During that time the tritium concentrations ranged from less than the LLD to 379,000 ± 200 pCi/L. Elevated tritium concentrations (>200 pCi/L) during 2012 resulted from the 2010 recycled condensate tank leak, and historic elevated tritium concentrations believed to be associated with the 2001 recycled condensate tank overflow.

In assessing the 2012 RGPP data Exelon Generation concluded that the operation of the plant has no adverse radiological impact on the environment, and there are no known active releases into the groundwater at the plant.

3.6.7 Non-radiological Releases to Groundwater

The LSCS Spill Prevention, Control and Countermeasures Plan (Exelon Generation 2012d) establishes procedures, methods, equipment and other requirements to prevent the release of chemicals, including controlled materials and oil and to mitigate the effects of any inadvertent releases.

LSCS has had one non-radioactive, reportable release to groundwater. In 1999 during the removal of underground storage tanks, one waste oil tank was found to have leaked. Notifications were made to the National Response Center (Incident No. 504538) and the Illinois Emergency Management Agency (IEMA) (Incident No. 992477). The released liquid was sampled, and free product was removed to the maximum extent practicable. No radiological materials were involved. The Station entered the IEPA Leaking Underground Storage Tank (LUST) regulatory process to disposition the site. On February 9, 2005, IEPA issued a letter of "No Further Remediation" for the area. This letter was registered with the LaSalle County Recorder's Office on March 9, 2005, as required. The NFR letter formally closes the LUST incident (Exelon Generation 2005).

Table 3.6-1 LSCS Annual Illinois River Water Intake and Blowdown

Unit	2008	2009	2010	2011	2012	Average
Illinois River Water Intake						
gpy	16,113,600,000	28,598,400,000	25,876,800,000	23,328,000,000	28,857,600,000	24,554,880
gpm	30,658	54,411	49,233	44,384	54,904	46,718
cfs	68	121	110	99	122	104
Illinois River Blowdown						
gpy	7,349,040,000	19,405,008,000	13,685,976,000	11,961,072,000	14,005,656,000	13,281,350,400
gpm	13,982	36,920	26,039	22,757	26,647	25,269
cfs	31	82	58	51	59	56
Consumptive Use						
gpy	8,764,560,000	9,193,392,000	12,190,824,000	11,366,928,000	14,851,944,000	11,273,529,600
gpm	16,675	17,491	23,194	21,627	28,257	21,449
cfs	37	39	52	48	63	48

gpy = gallons per year
gpm = gallons per minute
cfs = cubic feet per second
Sources: Exelon Generation 2008a, Generation 2009, Exelon Generation 2010a, Exelon Generation 2011a, Exelon Generation 2012a

Table 3.6-2 Public Groundwater Supplies within 10 Mi (16 km) of LSCS

Public Water Supply Name	Distance from Site [km] (mi)	Well No.	Date Drilled	Well Depth [m] (ft)	Aquifer	Pumping Rate [L/min] (gpm)	Average Daily Use [L/min] (gpd)
Seneca	8 (5)	1	1927	213 (700)	Oneota	NA	NA
		2	1942	214 (704)	Oneota	0.75 (285)	526 (200,000)
Marseilles	10 (6)	2	1920	204 (670)	Oneota	NA	NA
		3	1953	259 (850)	Potosi	NA	1,249 (475,000)
		4	1972	467 (1,466)	Ironton-Galesville	2.23 (850)	NA
Illini State Park	10 (6)	1	1934	134 (440)	NA	NA	NA
		2	1936	154 (500)	New Richmond	NA	NA
Kinsman	10 (6)	3	1936	216 (710)	St. Peter Sandstone	NA	NA
		4	1972[?]	239 (785)	St. Peter Sandstone	NA	79 (30,000)
Ransom	11 (7)	1	1907	99 (325)	Pennsylvanian	NA	NA
		2	1932	154 (500)	Galena-Platteville	NA	92 (35,000)
		3	1946	85 (280)	Pennsylvanian	NA	NA
		4	1971	248 (815)	St. Peter Sandstone	NA	NA
Grand Ridge	14 (9)	1	1915	49 (162)	Ticona Buried River Valley	0.29 (110)	NA
		2	1926	47 (156)	Ticona Buried River Valley	0.2 (75)	276 (105,000)
		3	1962	58 (190)	Ticona Buried River Valley	0.75 (285)	NA

gpm – gallons per minute
gpd – gallons per day
Source: Exelon Nuclear 2012a

PWS – Public Water Supply
NA - not available

Table 3.6-3 Wells within a 1-mi (1.6-km) Radius of LSCS

Well Id[a]	ISGS API ID	Owner	Use	Date Installed	Well Depth [m] (ft)	Aquifer / Bedrock Type
1	120992820900	Gage, Duane & Kathy	Private	2011	91 (300)	Gray shale & limestone
2	120992547800	David, Mike	Private	1997	152 (500)	St. Peters Sandstone
Well #2	120990234900	Commonwealth Edison	Not Available	1972	494 (1620)	Ironton-Galesville Sandstone
4	120992744500	Frye, Richard	Private	2004	165 (540)	Sandstone
5	120992811400	Invenergy LLC	Commercial	2009	171 (560)	St. Peters Sandstone
6	120990041700	Rose, A. D.	Not Available	1916	57(187)	Not Available
Well #1	120992245100	Commonwealth Edison	Not Available	1974	496.5 (1629)	Ironton-Galesville Sandstone
8	120992464100	Commonwealth Edison	Surface Water Recharge Well	1992	235 (7700)	Limestone
9	120990041600	Marsh, J. J.	Not Available	1916	81 (265)	Not Available

Source: ISGS Undated

a The well ID refers to the numbers on Figure 3.6-1.

API – American Petroleum Institute

Wells #1 and #2 are the LaSalle production wells

Table 3.6-4 LSCS Annual Groundwater Use [L/min] (gpm)

Well ID	2008	2009	2010	2011	2012	Average
Well #1 (API 120992245100)	95.73 (25.29)	87.93 (23.23)	94.59 (24.98)	52.88 (13.97)	62.6 (16.55)	78.7 (20.80)
Well #2 (API 120990234900)	0	6.24 (1.65)	0	83.5 (22.07)	16.7 (4.41)	20.1 (5.30)
Total Groundwater Use (gpm)	95.73 (25.29)	94.18 (24.88)	94.59 (24.98)	36.04	79.3 (20.95)	

API = American Petroleum Institute
gpm = gallons per minute
Source: Exelon Generation 2008a, Generation 2009, Exelon Generation 2010a, Exelon Generation 2011a, Exelon Generation 2012a

3.7 Ecological Resources

LSCS occupies 1,568 ha (3,875 ac) in LaSalle County, Illinois. The Station's 833 ha (2,058 ac) cooling pond, which serves as the heat sink for dissipation to the atmosphere of waste heat from LSCS, was created by constructing dikes that rise above the surrounding land (ComEd 1977), and by pumping water into the dry, diked area through a pipeline from the Illinois River, which is located approximately 5.6 kilometers (km) (3.5 miles [mi]) north from the cooling pond.

According to the land classification system used by the U.S. Forest Service, which is based on climate, geology, topography, and vegetation, LSCS is within the Central Loess Plains Section of the Prairie Parkland (Temperate) Province of the Prairie Division of the Humid Temperate Domain. The classification Humid Temperate Domain describes a region that is affected by both tropical and polar air masses, resulting in pronounced seasons and strong annual cycles of temperature and precipitation. The Prairie Division is dominated by tall grasses with subdominant broad-leaved plants (forbs). Rates of precipitation and evapotranspiration are roughly equal, leaving little moisture available for tree growth. The vegetation consists primarily of tall prairie grasses and forbs, with trees nearly absent, except in depressions and valleys where tree roots can reach the water table. The Prairie Parkland (Temperate) Province is typically a gently rolling area of plains and low hills, with some higher hills and steep bluffs bordering river valleys. Dominant vegetation in the Prairie Parkland (Temperate) Province originally consisted of alternating prairie and deciduous forest, but much of this region has been converted to agriculture. In addition, many of the native prairies have become overgrown with trees and shrubs, and no longer resemble prairie habitats. The climate within the Prairie Parkland (Temperate) Province consists of hot summers and cold winters, with precipitation ranging from 50 to 100 cm (20 to 40 in) annually. The Central Loess Plains Section is composed of smooth and irregular plains covered with loess, which is wind-deposited fine-grained silt or clay. Vegetation communities in The Central Loess Plains were historically bluestem prairie on uplands and floodplain forests in river and creek drainages. Most small wetlands were drained when the land was converted to agriculture. Today, the Central Loess Plains is predominantly highly productive farmland, with approximately 60 percent in crops and 25 percent used for grazing (Exelon Generation 2013b).

Land use in LaSalle County is primarily agricultural, and soybeans is the most abundant crop (Exelon Generation 2013b). The area surrounding the Station is rural and agricultural, with numerous wind turbines.

3.7.1 Aquatic Communities

3.7.1.1 Introduction

The Illinois River is formed by the confluence of the Des Plaines and Kankakee Rivers in eastern Grundy County, Illinois. From its origin, the Illinois River flows west, then southwest, for 439 km (273 mi) before emptying into the Mississippi River (Lerczak, et.al 1994). Six major tributaries --- the Fox River, the Vermillion River, the Mackinaw River, the Spoon River, the Sangamon River, and the La Moine River -- and many smaller streams join the Illinois River downstream of LSCS as the Illinois River flows to the Mississippi (ISWS 2003).

The Illinois River is part of the Illinois Waterway, which provides a navigable link between Lake Michigan and the Mississippi River, and ultimately the Gulf of Mexico. This waterway consists of the Illinois River, the Des Plaines River, the Chicago Sanitary & Ship Canal, and part of the Chicago River, and is made navigable by a series of eight locks and dams along the Illinois River and its tributaries (ISWS 2002). The waterway ends at Grafton, Illinois, about 35 mi (56 km) upstream of St. Louis, Missouri, where the Illinois River joins the Mississippi River.

Four of the locks and dams (Thomas J. O'Brien, Lockport, Brandon Road, and Dresden Island) are upstream of LSCS and four (Marseilles, Starved Rock, Peoria, and LaGrange) are downstream. The LSCS river screen house (intake for cooling pond makeup) is at river mile (RM) 249.5 (River km [Rkm] 401.5); the LSCS discharge/blowdown is at RM 249.4 (Rkm 401) (USACE 1998). The Dresden Island Lock and Dam is 22 mi (36 km) upstream of the LSCS intake at RM 271.5 (Rkm 437) (USACE 1998). The Marseilles Lock and Dam is 2.4 mi (3.5 km) downstream of the LSCS discharge at RM 247 (Rkm 397.5) (USACE 1998).

The Upper Mississippi River System, of which the Illinois River is a critical component, was declared a "nationally significant ecosystem" by Congress in the Water Resources Development Act of 1986 (Section 1103 of the WRDA of 1986 is also called the "Upper Mississippi River Management Act of 1986"). Aside from setting up a framework for state and federal agency cooperation, the WRDA of 1986 authorized the appropriation of more than $120 million to "undertake a program for the planning, construction, and evaluation of measures for fish and wildlife habitat rehabilitation and enhancement," more than $53 million for the "implementation of a long-term resource monitoring program," and more than $7 million for the "implementation of a computerized inventory and analysis system." Section 519 ("Illinois River Basin Restoration") of the WRDA of 2000 called for the Secretary of the Army in consultation with Illinois and federal resource agencies to develop a comprehensive plan for the purpose of restoring, preserving, and protecting the Illinois River basin that would provide for sediment removal programs; fish and wildlife habitat conservation and rehabilitation programs; land and water resources stabilization and enhancement programs; long-term monitoring programs; and a computerized inventory and analysis system. The WRDA of 2000 also provided funding for any "necessary" studies and analyses, as well as critical restoration projects that "will produce…immediate and substantial restoration, preservation, and protection benefits…"

3.7.1.2 Physical Setting

The Illinois River watershed has a drainage area of 75,156 km^2 (28,906 mi^2) of which approximately 64,000 km^2 (25,000 mi^2) are located in Illinois with the rest in Indiana and Wisconsin (ISWS 2002; ISWS 2003). The Illinois River watershed is generally flat with rich organic soil, making it one of the most productive agricultural regions in the United States. As of 2002, more than 80 percent of the Illinois River basin was used for agricultural purposes (ISWS 2002).

3.7.1.3 Hydrology

LSCS's river screen house, from which makeup water is pumped to the cooling pond, stands on the south shore of the Illinois River at (RM 249.5 (Rkm 401.5). The cooling pond's blowdown discharges to the river at RM 249.4 (Rkm 401). The USGS maintains a permanent gaging station downstream of LSCS at Marseilles, IL, at RM 246.5 (Rkm 398) (USGS 2013b). This gaging station is 0.8 km (0.5 mi) downstream of the Marseilles dam and 11 km (6.9 mi) upstream of where the Fox River enters the Illinois River (USGS 2013b). However, since 1993, the USGS has measured Illinois River flows (discharge) from a boat anchored downstream of the permanent gage and below the Marseilles Lock, at approximately RM 244 (Rkm 393).

As described in Section 3.6.1, for water years 1920-2012, annual mean flow at Marseilles ranged from 158,093 to 505,456 L/sec (5,583 to 17,850 cubic feet per second [cfs]) and averaged 304,689 L/sec (10,760 cfs) (USGS 2013b). Daily mean flows over the same period ranged from 13,054 to 2,888,318 L/sec (461 to 102,000 cfs). Flows at the Marseilles gaging station are highest in the spring (March-May) and lowest in late summer and fall (August-October).

3.7.1.4 Water Quality

The effects of urban pollution (domestic and industrial wastewater discharges) and extensive agricultural development (agricultural chemicals and disturbed soils in surface runoff) on the water quality of the Illinois River are discussed in Section 3.6.5. The impacts of deteriorating water quality on the aquatic communities of the Illinois River between 1870 and 1970 were profound, and included the loss of sensitive species, including freshwater mussels; overall reductions in aquatic species diversity; a shift from pollution-intolerant to pollution-tolerant fish species; a decline in planktivorous, big-river fish species, such as the paddlefish (*Polydon spathula*); and a decline in the abundance of many recreationally- and commercially-important fish species, including native black basses (*Micropterus* spp.) and walleye (*Stizostedion vitreum*).

The passage of the Illinois Environmental Protection Act in 1970 and the federal 1972 Clean Water Act imposed strict water quality standards on point-source dischargers and compelled municipal and industrial dischargers to improve and modernize wastewater treatment facilities. In the years that followed, water quality in the basin began to improve. Improved wastewater treatment significantly lowered levels of ammonia-nitrogen and organic pollutants in the Illinois River. Ammonia is highly toxic to aquatic organisms, and its decomposition in natural waters to less-toxic compounds (nitrite and nitrate) consumes oxygen. Similarly, organic pollutants (e.g., human and animal wastes) create biological oxygen demand (BOD) as they decompose.

By the time biological monitoring for LaSalle County Station began in the early 1970s, the river's water quality had begun to improve and its aquatic communities were showing the first signs of recovery. The Final Environmental Statement for LaSalle County Station characterized the water quality of the Marseilles Pool of the Illinois River as "characteristic of a river recovering from upstream pollution" (NRC 1978). The FES noted that organic pollution from upstream domestic sewage effluents, in particular, had contributed to high fecal coliform levels and periods of low dissolved oxygen.

Since the mid-1970s, water quality in the river has continued to improve (see Section 3.6.5), and fish communities are no longer dominated by pollution-tolerant species. These changes in fish communities are discussed in detail in the sections that follow.

The Illinois River is classified by the Illinois Pollution Control Board as General Use water (Section 303.201 of Title 35, Part 303, Subpart B of the Illinois Administrative Code). General Use waters are subject to the water quality standards in Subpart B of Part 302 of the regulation, which include standards for dissolved oxygen (DO), temperature, nutrients (e.g., phosphorus), a range of chemical constituents, and radioactivity. The Illinois River from the Dresden Generating Station discharge canal downstream to Plum Island (Starved Rock State Park), which encompasses the entire Marseilles Pool, is one of the stream segments in Appendix D to Part 302 that are afforded "enhanced dissolved oxygen protection." DO concentrations in these streams/stream segments must be not less than 5.0 mg/L at any time during March through July and not less than 4.0 mg/L at any time during August through February.

The stream segment (IL_D-23) receiving the discharge from LSCS NPDES-permitted Outfall 001 is identified in the draft Illinois Integrated Water Quality Report and Section 303(d) List, 2014 as "impaired waters" (IEPA 2014a). Mercury, PCBs, and fecal coliform bacteria are the listed causes of impairment. These pollutants are attributed to atmospheric deposition or "unknown sources." Releases of PCBs and complex metal-bearing waste streams are prohibited by NPDES Permit IL0048321.

In its most recent Sports Fish Consumption Advisory (IDPH 2013a), the Illinois Department of Public Health recommended that anglers who fish in the upper Illinois River (from its headwaters to the Marseilles Dam) restrict their ingestion/intake of four fish species (Table 3.7.1-1).

There is also a statewide methylmercury advisory (for all waters) that cautions against sensitive populations (young children and women of childbearing age) eating more than one meal per week of “predator fish” (e.g., black bass, striped bass, white bass, pike, walleye), as these piscivorous species tend to bioconcentrate mercury (IDPH 2013a).

3.7.1.5 Aquatic Communities

Illinois River

The Illinois Natural History Survey (INHS) has monitored fish populations of the Illinois River since 1957, employing the sampling method (electrofishing) that is generally regarded as the least biased and performing sampling in late summer to minimize the confounding effects of high or fluctuating river levels (Lerczak, et.al 1994; Lerczak 1996). To facilitate between-year and between-river section comparisons, the river was divided into three sections or reaches, based on the amount of “non-channel” habitat (i.e., sloughs, backwaters, and floodplain lakes) present: Upper (from RM 273 to RM 231), Middle (RM 231 to RM 80), and Lower (RM 80 to confluence with Mississippi River). The LSCS discharge is at RM 249.4, placing it in the Upper Illinois River study section. The Upper River section is characterized by a relatively narrow river valley and relatively steep gradient, and has very little backwater habitat. The Middle River section is wider and has the most backwater habitat. The Lower River was historically the widest portion of the river and had extensive backwater habitats, but has had its floodplain separated from the main river channel by levees.

Lerczak et al. (1994) (Lerczak, et.al 1994) presents results of the first 37 years (1957 to 1993) of INHS fish population monitoring, but samples were collected in only 29 of 37 years. In some years, water levels and water temperatures did not meet specified criteria and sampling was either not conducted at all or was discontinued due to rising river levels or too-low water temperatures (Lerczak, et.al 1994).

Lerczak et al. (1994) (Lerczak, et.al 1994) examined the relative abundance of centrarchids, regarded as indicators of good water quality, and carp and goldfish, regarded as indicators of poor water quality. In the Lower River, there was a slight upward trend (and considerable variability) in catch rates of centrarchids from 1962-1992 and a steady downward trend in catches of carp (Lerczak, et.al 1994). Goldfish and carp-goldfish hybrids were collected in only two years, 1974 and 1991, and in small numbers. In the Middle River, no statistically significant trends were evident with respect to centrarchids, but catches of carp and carp-goldfish hybrids showed an obvious downward trend between 1962 and 1992 (Lerczak, et.al 1994). In the Upper Illinois River, which includes the Marseilles Pool, there was a clear-cut upward trend in catches of centrarchids from 1962-1992 and a corresponding decline in catches of carp, goldfish, and carp-goldfish hybrids (Lerczak, et.al 1994).

Lerczak et al. (1994) (Lerczak, et.al 1994) noted that, independent of substantial improvements in Illinois River water quality over the thirty-plus years of INHS monitoring, there has been habitat degradation, especially in lower and middle river reaches, caused by soil erosion and sedimentation. The effect of water quality improvements on fish populations in the Upper River, in particular, was obvious. Centrarchids made up 0 to 0.68 percent of all fish collected annually over the 1962-1966 period, and 8.65 to 15.01 percent of all fish collected over the 1989-1993 period (Lerczak, et.al 1994). Carp, on the other hand, made up 11.60 to 28.66 percent of all fish collected annually from 1962-1966 and 3.93 to 7.62 percent of fish collected from 1989-1993 (Lerczak, et.al 1994).

In addition to the shift to less pollution-tolerant groups of fish, the INHS researchers observed statistically significant decreases in external abnormalities (i.e., lesions and ectoparasites) in "water-column fishes" (species that prefer deeper water to the shallows or bottom sediments) in all river reaches, a change they attributed to "improvements in water quality…which occurred over the same time period" (Lerczak, et. al 1994). No such change was observed in sediment-dwelling fish species, possibly indicating that pollutants in sediment were more toxic or more persistent.

Lerczak (1996) (Lerczak 1996) summarized results of 39 years (1957-1995) of INHS fish population monitoring in the Illinois River, emphasizing differences between the 1960s and 1990s. In the lower Illinois River, a relatively small number of species (11) dominated catches in both the 1960s and the 1990s, but the 1990s saw an increase in desirable species (e.g., bluegill) and a corresponding decrease in pollution-tolerant species (e.g., common carp) (Lerczak 1996). In the middle and upper river reaches, species diversity increased and desirable species generally increased in abundance. Bluegill catch rate in the upper river was less the one fish per hour in the 1960s but averaged 12 fish per hour in the 1990s. Lerczak (1996) (Lerczak 1996) observed that "the most noteworthy changes have occurred in the upper river, historically the most degraded segment due to its nearness to Chicago area pollution sources."

Lerczak (Lerczak 1996) attributed these changes in fish communities to improved water quality (especially higher DO concentrations) stemming from pollution control efforts associated with the Clean Water Act and various state initiatives. While bringing improved and modernized sewage treatment and industrial waste treatment systems on line clearly reduced organic and toxic inputs to the river system, and many indicators of water quality showed substantial improvements between the 1960s and 1990s, siltation continued to be a significant problem. The 1980s and 1990s also saw the appearance of more and more invasive species, creating a whole new set of challenges for native fish species. McClelland et al., (McClelland, et al. 2012) updated the INHS Long Term Monitoring Program (1957-2009) findings in light of continuing water quality improvement and the increasing prevalence of non-native fish species in the river. While Lerczak (Lerczak, et. al 1994; Lerczak 1996) examined the fish communities of upper, middle, and lower reaches of the river, McClelland et al. (McClelland, et al. 2012) chose to group the same sampling stations into only two reaches, upper and lower. He did so based on the fact that the stream gradient is higher and the substrate rockier from the headwaters to the "Big Bend" area at Hennepin (RM 208) while the river below Hennepin is characterized by lower stream gradients, a wider flood plain, and generally softer substrates.

McClelland et al. (McClelland, et al. 2012) noted that river-wide, native fish species richness increased significantly from 1957 to 2009 (McClelland, et al. 2012). Native species richness increased more rapidly in the upper river (one new species every 3 years) than in the lower river (one new species every 5 years). Four darters, two topminnows, three dace, and one centrarchid were added to the INHS's Illinois River collections between 1985 and 2009. Native fish species abundance (catch per unit of effort) decreased from 1957 until 1976 in the lower Illinois River, and increased thereafter. Native fish abundance decreased from 1957 until 1978 in the upper river, and increased thereafter (McClelland, et al. 2012).

With regard to species assemblages, the change over the 50-plus-year period has been striking (see Table 3.7.1-2). Between 1957 and 1969, 13 fish species were routinely collected (comprised 90 percent or more of total catch), while between 1990 and 2009, 17 species were routinely collected (comprised 90 percent or more of catch). Relative abundance of desirable, recreationally important species (e.g., channel catfish, bluegill, largemouth bass, and smallmouth bass) has increased throughout the sampled reaches of the river, while relative abundance of less desirable species (e.g., common carp and goldfish) has decreased.

McClelland et al. (McClelland, et al. 2012) attribute these changes in fish community structure in the Illinois River to rehabilitation efforts in the basin. They note that watershed improvements have allowed centrarchids in particular to flourish, especially in parts of the upper river where aquatic vegetation has returned.

Marseilles Pool and LSCS Vicinity

The Final Environmental Statement for LaSalle County Station characterized the water quality of the Marseilles Pool of the Illinois River as “characteristic of a river recovering from upstream pollution” (NRC 1978). Although Illinois River water quality had begun to improve, construction and pre-operational monitoring (1974-1976) in the vicinity of the LSCS intake and discharge showed a predominance of hardy, pollution-tolerant biota. Benthic macroinvertebrate samples consisted primarily of oligochaetes and chironomids (NRC 1978), both pollution-tolerant groups that are associated with degraded water quality. Likewise, fish samples were dominated by hardy, pollution-tolerant species such as emerald shiner, gizzard shad, carp, and bluntnose minnow. Species richness was slightly higher downstream than upstream of the LSCS intake and discharge (NRC 1978). Fish coefficients of condition (condition factors) were low, whereas parasite loads were high. The FES concluded that:

> “The low species abundance and diversity, low condition factors, and the degree of external parasitism…in this area of the Illinois River are indicative of a poor aquatic environment. Barge traffic, habitat alternation, and heavy pollution loads have contributed significantly to the poor water quality of this stretch of the river, which only supports major populations of pollution-tolerant fish.” (NRC 1978)

The Illinois Natural History Survey’s Long Term Monitoring Program encompasses stations along the entire length of the Illinois River, including three in the Marseilles Pool. Two of these stations --- Waupecan Island and Johnson Island --- are upstream of the LSCS intake, and one, Ballard Island, is a short distance downstream of the LSCS discharge. To support the discussion in this environmental report, the INHS provided Exelon Generation with 1993-2012 fish monitoring results for these three stations (Fritts 2013). Changes in fish populations at these monitoring locations over the 20-year period generally mirrored those seen elsewhere in the river, with recreationally important species such as bluegill and largemouth bass (Centrarchidae family) becoming relatively more abundant and less-desirable species such as carp and goldfish becoming less abundant. These trends were evident whether the monitoring location was up- or downstream of the LSCS intake and discharge, suggesting that the plant has little or no impact on fish populations in the Marseilles Pool. Figures 3.7.1-1, 3.7.1-2, and 3.7.1-3 show relative abundance of centrarchids and carp/goldfish at the three Marseilles Pool monitoring locations between 1993 and 2012.

August 2013 Marseilles Pool Sampling Results

Exelon commissioned EA Engineering, Science, and Technology (EA) to survey benthos and fish in August 2013 at several Marseilles Pool sampling stations that were used in the 1970s for LSCS baseline (pre-construction and pre-operational) surveys. Fish were collected using a boat-mounted electrofishing unit and a beach seine. Benthic macroinvertebrates were collected using Hester-Dendy (artificial substrate) samplers and Ponar grab sampler (“dredge”). Results from the limited 2013 surveys were compared to surveys conducted in the 1970s (“pre-operational”) and in 1999 (“operational”).

Results from the Illinois Natural History Surveys' indicate that pre-operational (1974-1978) and operational (1999) fish assemblages were generally similar, comprised of common forage species (e.g., emerald shiner, spotfin shiner, and gizzard shad), rough fish (species that are not highly regarded by recreational anglers) species (e.g., smallmouth buffalo, freshwater drum, and common carp), and game species (e.g., channel catfish, largemouth bass, and smallmouth bass) (EA 2014). The same species dominated the most recent collecting event, albeit with slightly lower species richness, but the difference can be attributed to the reduced sampling intensity in 2013 (EA 2014). No state or federally listed fish species was collected in pre-operational or operational studies (EA 2014).

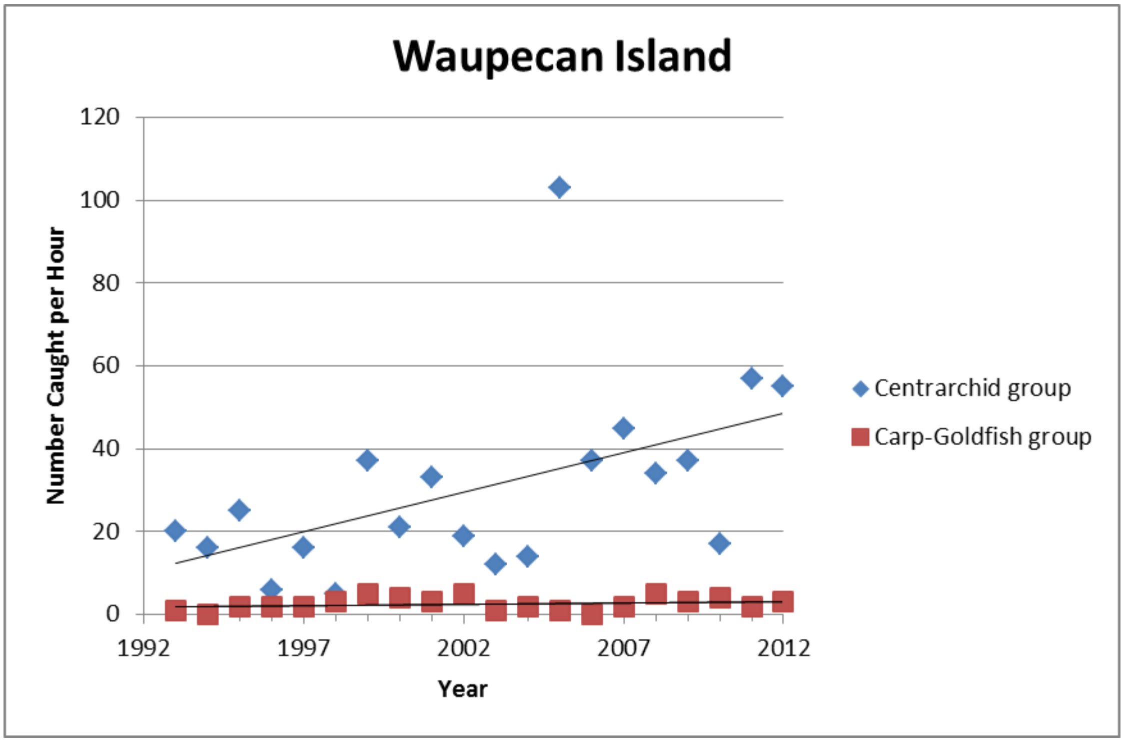

Figure 3.7-1 Waupecan Island Fish Collections, 1993-2012

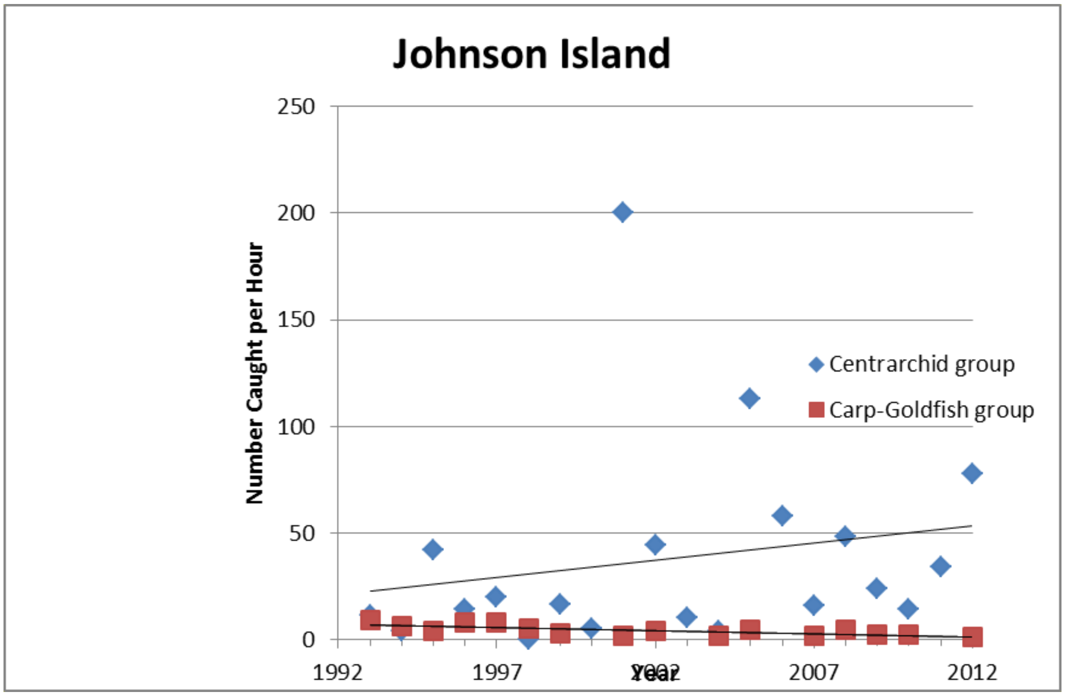

Figure 3.7-2 Johnson Island Fish Collections, 1993-2012

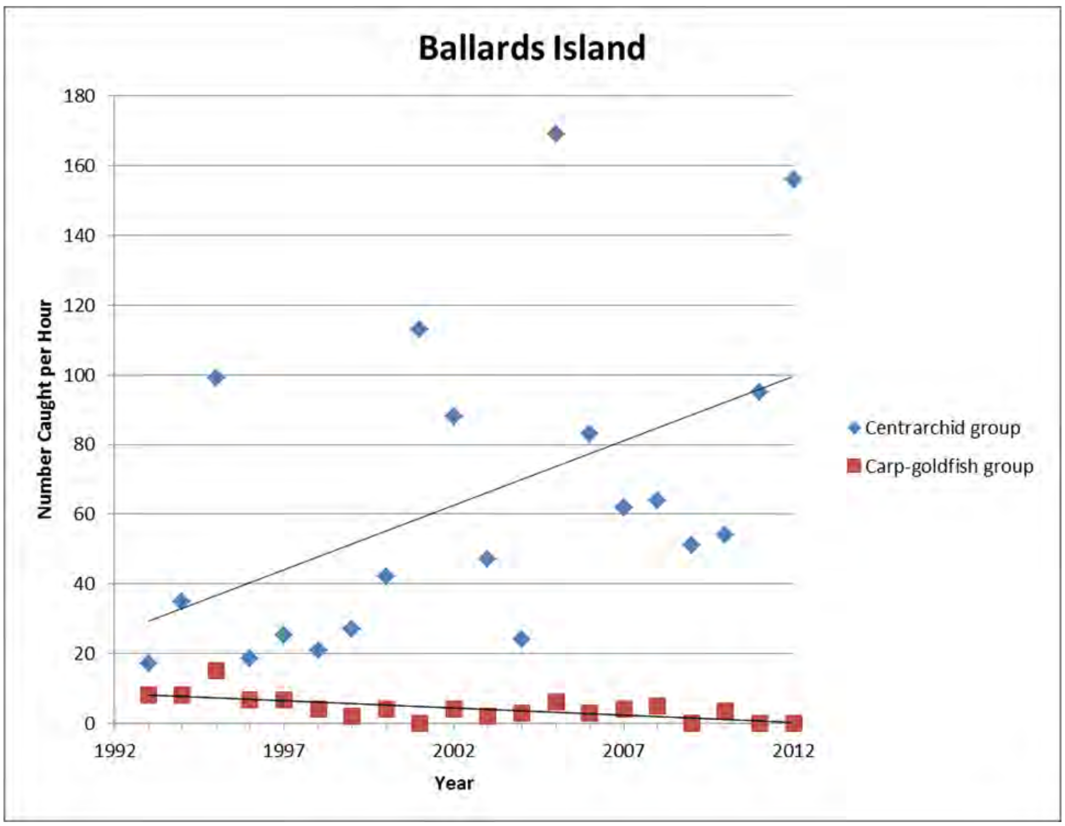

Figure 3.7-3 Ballards Island Fish Collection, 1993-2012

LSCS Cooling Pond

In the LSCS Final Environmental Statement for operation, the NRC staff suggested several factors (basin configuration, predicted high nutrient loading rates and high temperatures, likely introduction of undesirable fish species) that could be detrimental to the establishment of a successful fishery in the LSCS cooling pond (NRC 1978). Nevertheless, the cooling pond has developed into a highly successful recreational fishery featuring largemouth bass, white and hybrid bass, and catfish (channel and blue). Smallmouth bass, generally regarded as a "cool-water species" are often caught in spring. When water temperatures are highest, in late summer, most of the fishing effort is directed towards catfish.

The LSCS cooling pond, which is generally open to the public from mid-March until mid-October, provides anglers in north-central Illinois with opportunities to pursue a variety of sport fish, including channel catfish, blue catfish, sunfish (bluegill and redear), largemouth bass, smallmouth bass, and hybrid bass. The impoundment has been actively managed by Illinois DNR since 1986. Management activities include regular electrofishing surveys designed to determine population/age structure of important recreational species, evaluations of fish condition (length-weight relationships), assessments of forage fish abundance, periodic creel surveys to determine angler preferences and success rates, and an aggressive fish stocking program to compensate for the generally low levels of natural reproduction/recruitment in the impoundment. All fish stocked into the impoundment come from the LaSalle Fish Hatchery, which is on land leased by Illinois DNR from Exelon Generation on the southwest shore of the LSCS cooling pond (see Figure 2.2-1).

The LaSalle Fish Hatchery has been operated by IDNR since 1994 (DNR 2014). It was previously operated by Southern Illinois University–Carbondale as a research facility. The LaSalle Hatchery consists of 16 rearing ponds which total 35.5 acres of water. This hatchery currently rears six species for stocking into Illinois public waters. Both cool- and warm-water species are raised. Artificial and natural spawning methods are used. Cool-water species are stocked as either "fry" (newly hatched less than 2.5 cm [1 in] long) or "fingerlings" (2.5 cm [1 in] to 15 cm [6 in] fish), while warm water species are only stocked as fingerlings (DNR 2014).

EA Engineering, Science and Technology (2002) (EA 2002) described the evolution of the LSCS cooling pond fish community and provided an assessment of its recreational and forage fish populations (as observed in 2001). After the cooling pond was filled with water pumped from the Illinois River in 1978, it was stocked with largemouth bass and bluegill. When the LaSalle fish hatchery became operational in 1981, Southern Illinois University biologists experimented with stocking smallmouth bass, walleye, muskellunge, and hybrid striped bass. The experiment indicated that the pond was not well-suited for walleye and muskellunge and their stocking was discontinued in 1987 and 1988, respectively.

The cooling pond was opened to the public in 1986 after all stakeholders and regulatory agencies were satisfied that thermally-enriched waters of the pond could support a successful recreational fishery and did not represent a public health risk. Recreational activities including boating, sailing, and fishing were deemed acceptable, while swimming and water skiing were not. The cooling pond quickly became a popular destination for fishermen. In 1994, the emphasis at the LaSalle fish hatchery shifted from fisheries research to fisheries management, and operation of the hatchery was transferred from Southern Illinois University to IDNR.

Between 1997 and 2001, more than 800,000 fingerlings were stocked in the cooling pond, including 241,283 largemouth bass, 111,288 smallmouth bass, 138,574 blue catfish, 267,676 bluegill, 25,361 crappie, and 39,464 striped bass hybrids (EA 2002). These stockings reflected the move away from cool-water species to the warm-water species more likely to flourish in the cooling pond. Hybrid striped bass and blue catfish were considered ideal species for the cooling pond because of their tolerance for higher water temperatures and the expectation that they would be effective in controlling shad, and gizzard shad in particular.

As of 2001, largemouth bass in the cooling pond were plentiful (based on catch per unit effort; CPUE) and in good condition (based on high relative weight values), but the scarcity of spawning and rearing habitat meant that recruitment rates were low (EA 2002). Therefore the population was being maintained by the IDNR stocking program.

Smallmouth bass numbers were lower in 2001 than in previous years, but other indicators (relative weight and Proportional Stock Density) suggested that the overall condition of fish was improving and more catchable fish and “quality” fish were present (EA 2002).

Like smallmouth bass, catch-per-unit-effort for bluegill was lower in 2001 than in previous years, but other metrics (relative weight, Proportional Stock Density, and Relative Stock Density) were indicative of a healthy population (EA 2002).

Channel catfish abundance (as indicated by catch-per-unit-effort) and Proportional Stock Density values were generally higher in 2001 than in previous years, while condition (relative weight) varied little between 1997 and 2001 (EA 2002). In January 2002, blue catfish that had been stocked as fingerlings in the fall of 1999 began to appear in catches as 4.5 to 9 kilogram (kg) (10 to 20 pound [lb]) fish.

Since 2001, LSCS has had four reportable fish kills (in 2001, 2005, 2009 and 2010) in the cooling pond, and one small, unreported (approximately 100 shad) event in 2002. The largest event was in 2001, when approximately 95,000 fish were killed. As a result the Extreme Heat Implementation Plan was developed and is used to manage the cooling pond during extreme summer temperatures.

Exelon Generation and IDNR staffs meet annually to discuss cooling pond and land management activities at three Exelon nuclear plants, one of which is LSCS. The meeting minutes constitute a review of fishery management and fish stocking activities at the LSCS cooling pond. With respect to fishery management, the minutes document the transition to thermally-tolerant fish species which provide excellent recreational fishing opportunities while also controlling shad (and to an unknown extent, the invasive freshwater clam *Corbicula*) in the cooling pond. Fish stockings in recent years reflect this management emphasis, with more than a million blue catfish, bluegill, redear sunfish, smallmouth bass, largemouth bass, and hybrid striped bass fingerlings added to the impoundment between 2008 and 2012 (Table 3.7.1-3). Smallmouth bass, normally categorized as a cool-water species, can thrive in cooling ponds provided there are thermal refuges to which they can retreat in summer and provided populations are maintained by regular stockings. Smallmouth bass in the LSCS cooling pond do not appear to be thermally stressed, and meeting minutes document that they were in good condition (body weight relative to length) in 2011 and 2012 despite unusually high water temperatures.

Annual Exelon Generation and IDNR staff meeting minutes state that fish surveys in 2011 and 2012 indicated a flourishing bluegill population, with very high catch rates in the eastern portion of the cooling pond. Although fewer large largemouth bass were observed, “good numbers” of young-of-the-year and yearling fish were collected, suggesting that the population is stable, and could expand in the future. Smallmouth bass were abundant in the eastern portion of the cooling pond, and body condition of these fish was higher than in previous years. Channel catfish catch rates were lower in 2011 and 2012, but their body condition was improved. Threadfin shad densities were lower in 2011 than in previous years, but rebounded in 2012.

Gizzard shad densities were "about the same" in 2012, but body condition was higher than in earlier years.

IDNR biologists conduct special blue catfish surveys in the fall, as the blue catfish is perhaps the most-sought-after species in the cooling pond. Anglers regularly report catching blue catfish in excess of 23 kilograms (50 pounds). A creel survey in 2007 revealed that blue catfish were extremely popular among anglers and ranked first, by weight, in harvest. An estimated 14,500 kg (32,000 lb) of blue catfish were landed by anglers in 2007, twice the weight of any other species.

3.7.1.6 Invasive/Non-native Species

Non-native species such as the common carp and goldfish have been a part of the Illinois River fish community for many years, and are generally associated with degraded water quality. Both species are hardy, tolerant of low DO and high turbidity. These were the dominant non-native species in INHS collections between 1957 and 1985 (McClelland, et al. 2012). Non-native species richness increased significantly between 1985 and 2009, however (McClelland, et al. 2012). Seven non-native taxa were added to the species list after 1985: hybrid striped bass (*Morone saxatilis* x *Morone chrysops*), grass carp (*Ctenopharyngodon idella*), bighead carp (*Hypophthalmycthys nobilis*), silver carp (*Hypophthalmycthys molitrix*), round goby (*Neogobius melanostomus*), white perch (*Morone americana*), and the white perch-yellow bass hybrid (*M. americana* x *M. mississippiensis*) (McClelland, et al. 2012). In the upper river, non-native species richness increased significantly between 1957 and 2009. Abundance of non-native fish species declined from 1957 to 2000 in both the lower and upper river, then increased significantly. Bighead carp and silver carp were first collected by the INHS in 1995 and 1998, respectively, in the LaGrange Reach, well downstream of LSCS. Since 2000, population growth of these carp in the LaGrange Reach has been exponential (McClelland, et al. 2012).

Bryozoans are a phylum of common aquatic invertebrates that exist in large sessile colonies which can cause the biofouling of underwater piping systems, including the cooling systems of power plants. In 1996 bryozoans were discovered at the lake screen house, and treated with continuous chlorination which apparently killed the colony. In 2010 the bryozoan *Plumatella reticulata* was discovered in the Unit 1 cooling water system and unidentified bryozoans were found at the river screen house and in the cooling pond (HDR Engineering 2011). Since then bryozoan colonies are routinely found at both the river intake and the cooling lake (HDR Engineering 2012, HDR Engineering 2013, HDR Engineering 2014). Bryozoans are managed with biocides.

Zebra mussels are native to the Black and Caspian Seas, and have invaded Europe and North America. They were first discovered in North America in the Great Lakes in 1988, and since then have spread throughout North America's large river systems. They occur in densities high enough to clog water intakes. Exelon Generation began monitoring for zebra mussels in 1990, and has documented zebra mussel colonization at the LSCS intake structure and in the cooling reservoir since that time (see for example HDR Engineering 2010, HDR Engineering 2011, HDR Engineering 2012, HDR Engineering 2013, HDR Engineering 2014). Zebra mussels are managed with biocides but Exelon Generation has procedures for removing them manually should it become necessary. LSCS also monitors for Corbicula, however, none have been found at either the river screenhouse or the lake.

3.7.1.7 Special Status Aquatic Species

Both the Environmental Report – Operating License Stage (ComEd 1977) and the FES for LSCS (NRC 1978) observed that the aquatic communities of the Illinois River in the vicinity of the LaSalle County Station intake and discharge structures were dominated by pollution-tolerant species, reflecting poor water quality in this reach of the river. The FES noted that “there are no records, either old or recent, of any rare or endangered fishes in this stretch of the Illinois River” (NRC 1978).

However, the improved water quality and restoration efforts discussed earlier in this section have resulted in an increase in abundance of sensitive, pollution-intolerant species. Several darter and dace species, the blackstripe topminnow (*Fundulus notatus*) and the state-listed banded killifish (*F. diaphanus*) have appeared in INHS collections over the last 10 to 15 years (McClelland, et al. 2012). The banded killifish normally occurs in shallows of glacial lakes and in clear, sandy streams with weedy margins. Locally common in New England, Minnesota, Wisconsin, and Michigan, the species is rare in Illinois, found mostly in clear lakes in Lake and Cook counties. According to Illinois DNR records, banded killifish were collected in the Illinois River immediately upstream of its confluence with the Vermillion River between 2000 and 2010 (IDNR 2012a).

The Illinois Natural Heritage Database for LaSalle County has two state-listed mussels and three-state listed fish (IDNR 2012b), but does not provide locations. U.S. Fish and Wildlife Service’s (USFWS) Midwest Region website indicates no federally listed aquatic species occur in LaSalle County (USFWS 2012).

Table 3.7.1-1 Sport Fish Consumption Guidelines for 2013, Upper Illinois River

Species	Size	Meal Frequency	Contaminant of Concern
Common carp	All sizes	6 meals/year	PCBs
Channel catfish	All sizes	“Do not eat”	PCBs
Smallmouth bass	All sizes	1 meal/month	PCBs
White bass	All sizes	1 meal/month	PCBs

Source: IDPH 2013a
PCB = polychlorinated biphenyls

Table 3.7.1-2 Percentages of fish species contributing to approximately 90 percent of electrofishing catches in the Illinois River in three time periods (1957–1969; 1970–1989; 1990–2009)

Fish Species	1957 - 1969	1970 - 1989	1990 - 2009
Gizzard shad (*Dorosoma cepedianum*)	20.4	23.0	16.2
Common carp (*Cyprinus carpio*)	24.9	16.4	7.6
Emerald shiner (*Notropis atherinoides*)	19.3	10.7	10.6
Bluegill (*Lepomis macrochirus)*	2.8	6.2	13.1
Largemouth bass (*Micropterus salmoides*)	2.2	5.1	6.4
Green sunfish (*L. cyanellus*)	2.4	6.3	5.3
Channel catfish (*Ictalurus punctatus*)	N/A	3.5	5.6
Freshwater drum (*Aplodinotus grunniens*)	N/A	3.8	4.8
Black crappie (*Pomoxis nigromaculatus*)	1.8	4.2	2.9
Smallmouth buffalo (*Ictiobus bubalus*)	N/A	1.8	4.5
White bass (*Morone chrysops*)	N/A	2.9	2.8
Bigmouth buffalo (*I. cyprinellus*)	1.8	1.8	1.3
Goldfish (*Carassius auratus*)	6.6	2.2	n/a
River carpsucker (*Carpiodes carpio)*	N/A	1.8	1.6
Bluntnose minnow (*Pimephales notatus*)	N/A	N/A	2.3
White crappie (*P.s annularis*)	0.6	1.7	n/a
Common carp × goldfish (*C.s carpio × C. auratus*)	3.0	N/A	n/a
Quillback (*Carpiodes cyprinus*)	1.9	N/A	n/a
Black bullhead (*Ameriurus melas*)	1.4	N/A	n/a
Bullhead minnow (*Pimephales vigilax*)	N/A	N/A	2.9
Smallmouth bass (*M.s dolomieu*)	N/A	N/A	1.4
Orange spotted sunfish (*L. humilis*)	N/A	N/A	1.2

Source: McClelland, et al. 2012
N/A = fish species not part of 90 percent

Table 3.7.1-3 LSCS Cooling Pond Fish Stockings, 2008-2012

Species	Size Range in cm (in)	2008	2009	2010	2011	2012	Totals (annual avg)
Blue catfish	8 – 15 (3 - 6 in)	18,560	34,452	19,800	23,368	---	96,180 (19,236)
Bluegill	2.5 – 8 (1 - 3 in)	55,466	11,740	84,661	364,731	73,681	590,279 (118,056)
Redear sunfish	2.5 – 8 (1- 3 in)	34,151	---	4,830	4,830	---	43,811 (8,762)
Largemouth bass	2.5 – 15 (1 - 6 in)	66,395	51,207	50,434	30,470	84,166	282,672 (56,534)
Smallmouth bass	8 – 13 (3 - 5 in)	25,365	21,155	21,118	22,733	20,683	111,054 (22,211)
Hybrid bass	2.5 – 13 (1 - 5 in)	80,889	68,404	41,284	52,642	---	243,219 (48,644)
TOTAL		280,826	186,958	222,127	498,774	178,530	1,367,215 (273,443)

3.7.2 Terrestrial and Wetland Communities

Most of the LSCS property is used for generating facilities, support/maintenance facilities, roads and parking lots, the ISFSI, the switchyard, landscaped areas, and the cooling pond. Terrestrial communities include forest, scrub-shrub, grassland, old-fields, and wetlands.

The National Wetlands Inventory (NWI) wetlands mapper identifies the cooling pond, the intake and discharge canals, and the north and south storm water detention ponds west of the power block as diked/impounded lacustrine (lake or deep water) systems (USFWS 2013). The "diked/impounded" designation indicates that the area has "been created or modified by a man-made barrier or dam which obstructs the inflow or outflow of water" (USFWS 2013). Areas along the periphery of these water bodies have emergent vegetation and soil types that lead to a classification of man-made wetlands. The invasive common reed (*Phragmites australis*) is established in parts of the cooling pond, particularly along its western edge. In 2007 Exelon Generation began an eradication program using mechanical harvesting and aquatic-safe herbicides (Exelon Generation 2013b).

An open grassy area between the cooling pond and the power block, is bounded on the north by the discharge canal and on the south by the property boundary. This area and another, smaller area southwest of the power block, have a few scattered trees but are otherwise open and dominated by grasses. Approximately 4 ha (10 ac) in the area west of the cooling pond is actively managed as native prairie in partnership with Pheasants Forever (a habitat conservation organization) (Exelon Generation 2013b).

Almost all of the grassy area is uplands, with a few excavated isolated wetlands (USFWS 2013). These man-made wetlands are a remnant of the site's agricultural past (Exelon Generation 2013b). Three small excavated wetlands are about 1.4 km (0.9 mi) north of the discharge canal (USFWS 2013).

The makeup and blowdown pipeline corridor extends north from the cooling pond to the Illinois River within an irregular-shaped property boundary (Figure 2.2-1). This portion of the property supports upland habitats such as scrub-shrub, forest, grassland, and old-fields, and scattered wetlands. Most of the corridor is upland; common tree species in upland forests and scrub-shrub habitats include white oak (*Quercus alba*), red oak (*Q. rubra*), shagbark hickory (*Carya ovata*), sugar maple (*Acer saccharum*), hop hornbeam (*Ostrya virginiana*), hawthorn (*Crataegus spp.*), black cherry (*Prunus serotina*), and American elm (*Ulmus americana*) (ComEd 1977).

The corridor widens considerably as it approaches the Illinois River (Figure 2.2-1), and includes several wetlands. A few of the wetlands are excavated ponds (USFWS 2013). Palustrine (marsh) emergent and palustrine forested wetlands occur on the LSCS property near the river (USFWS 2013). Common tree species in these forested wetlands are American elm, black cherry, white oak, red oak, black oak (*Q. velutina*), shagbark hickory, bitternut hickory (*C. cordiformis*), hackberry (*Celtis occidentalis*), elm (*Ulmus* spp.), willow (Salix spp.), and sycamore (*Platanus occidentalis*) (ComEd 1977). The emergent wetlands are characterized by herbaceous vegetation such as cattail (*Typha* spp.) and horsetail (*Equisetum* spp.) (ComEd 1977).

Wildlife species at LSCS are typical of similar habitats in northeastern Illinois. Twenty-nine mammal species were recorded in baseline surveys conducted in the 1970s (ComEd 1977). Mammals frequently observed during the baseline surveys included the white-tailed deer (*Odocoileus virginianus*), cottontail rabbit (*Sylvilagus floridanus*), and opossum (*Didelphis virginiana*). The white-footed mouse (*Peromyscus leucopus*) and deer mouse (*P. maniculatus*) were the mammals most commonly trapped during the baseline surveys (ComEd 1977). Mammals commonly observed in recent years on site include the white-tailed deer, opossum, coyote (*Canis latrans*), beaver (*Castor canadensis*), groundhog (*Marmota monax*), and gray squirrel (*Sciurus carolinensis*) (Exelon Generation 2013b).

During baseline surveys in the 1970s, 120 bird species representing migrants and residents were recorded on or near LSCS (ComEd 1977). Common resident species included the horned lark (*Eremophila alpestris*), mourning dove (*Zenaidura macroura*), common crow (*Corvus brachyrhynchos*), robin (*Turdus migratorius*), yellow-shafted flicker (*Colaptes auratus*), Eastern meadowlark (*Sturnella magna*), and European starling (*Sturnus vulgaris*) (ComEd 1977). The most common upland game bird species were ring-necked pheasant (*Phasianus colchicus*), Northern bobwhite quail (*Colinus virginianus*), and mourning dove (ComEd 1977). The red-tailed hawk (*Buteo jamaicensis*) was the most common raptor (ComEd 1977).

The cooling pond provides habitat for waterfowl, such as mallards (*Anas platyrhynchos*) and Canada geese (*Branta canadensis*), and wading birds such as the great blue heron (*Ardea herodias*). The cooling pond also provides foraging habitat for the osprey (*Pandion haliaetus*) and migratory birds such as the white pelican (*Pelecanus erythrorhynchos*) (Exelon Generation 2013b).

The Eastern plains garter snake (*Thamnophis radix radix*) and the fox snake (*Elapha vulpina*) were the only reptiles recorded on the site during the surveys. No amphibians were recorded (ComEd 1977).

LSCS's "Wildlife at Work" program was certified by the Wildlife Habitat Council as continuing for two additional years from November 2013. The Wildlife Habitat Council is a nonprofit organization of corporations, conservation organizations, and individuals dedicated to restoring and enhancing wildlife habitat. The certification was awarded as a result of past and planned wildlife habitat enhancement and conservation activities at LSCS. Examples include (Exelon Generation 2013b):

> (1) Habitat restoration has been ongoing since 2007 through planting of swamp white oak and other native plants near the cooling pond as well as taking measures to control the invasive common reed (*Phragmites australis*);
>
> (2) Existing habitat enhancement for grassland nesting birds has been ongoing since 2004 through seeding, mowing, and controlled burns;
>
> (3) Bat species protection is planned through erection of artificial roosts and reducing the on-site use of pesticides;
>
> (4) Nesting habitat improvements are planned for Eastern bluebirds (*Sialia sialis*) through grasslands maintenance and erection of nest boxes in or adjacent to on-site grasslands.
>
> (5) Osprey platforms have been installed near the cooling pond

Table 3.7.2-1 lists special-status animal and plant species recorded in LaSalle County. The species in Table 3.7.2-1 are those that are state- or federally-listed as endangered or threatened. The county occurrences indicated in the table were based on records maintained by the USFWS (USFWS 2012) and IDNR (IDNR 2012b). According to the USFWS database (USFWS 2012) there are no records of species that are candidates for federal listing or that are proposed for federal listing in LaSalle County.

The only species listed in Table 3.7.2-1 that Exelon Generation is aware of being observed or recorded at LSCS is the state-listed peregrine falcon (*Falco peregrinus*). A pair of peregrine falcons nested on the roof of the auxiliary building several years ago, but no nesting has been observed in recent years. However, Exelon Generation personnel occasionally observe peregrine falcons flying in the vicinity of power block. Bald eagles (*Haliaeetus leucocephalus*) were observed in the vicinity during the 1970s (ComEd 1977), but Exelon Generation is not aware of bald eagle sightings at the Station in recent years. Although the USFWS removed the bald eagle from the federal list of threatened and endangered species in 2007, it is still federally protected under the Bald and Golden Eagle Protection Act and the Migratory Bird Treaty Act. The bald eagle is neither state-threatened nor state-endangered in Illinois. Federally protected species recorded in LaSalle County are discussed below, however, none have ever been observed on the LSCS property.

The Indiana bat (*Myotis sodalis*) is federally listed as endangered. Indiana bats hibernate during winter in caves or abandoned mines. During the summer, they migrate to wooded areas where they usually roost under loose tree bark on dead or dying trees. Indiana bats mate during the fall, and females store the sperm through winter and become pregnant in spring soon after they emerge from hibernation. They feed on flying insects near rivers and lakes and in uplands. Within Illinois, the Blackball Mine has been designated as critical habitat for this species (USFWS 2012). It is approximately 32 km (20 mi) west-northwest of LSCS.

The gray bat (*M. griescens*) is federally listed as endangered. Gray bats hibernate in deep, vertical caves during winter. In the summer, they roost in caves in limestone karst near rivers. Gray bats eat a variety of flying insects near rivers and lakes (USFWS 2012). Federally designated critical habitat has not been established for this species.

The Northern long-eared bat (*Myotis septentrionalis*) was proposed for listing by the U.S. Fish and Wildlife Service in October 2013 (78 FR 191, 61046-61080). On June 30, 2014 the U.S. Fish and Wildlife Service announced (79 FR 125, 36698-36699) a 60-day re-opening of the comment period for the proposed rule and a six-month extension on the deadline for making a final determination on whether or not to list the species.

This species over-winters (hibernates) in large caves and mines and is often found in forested areas in summer, where it forages along ridges and hillsides, and, less often, over forest clearings and forest roads. In summer, long-eared bats roost singly or in small colonies under bark and in cavities of both dead and living trees. Long-eared bats are also known to roost in buildings, barns, sheds, cabins, and bat houses (artificial roosts).

Decurrent false aster (*Boltonia decurrens*) is federally listed as threatened. It grows on moist, sandy floodplains and in prairie wetlands along the Illinois River. It relies on periodic flooding to scour away other plants that compete for the same habitat (USFWS 2012). Federally designated critical habitat has not been established for this species.

Leafy prairie-clover (*Dalea foliosa*) is federally listed as endangered. In Illinois, it is found in prairie remnants along the Des Plaines River, in thin soils over limestone substrate. It favors sites with a wet spring and fall and a dry summer (USFWS 2012). Federally designated critical habitat has not been established for this species.

The Eastern prairie fringed orchid (*Platanthera leucophaea*), federally listed as threatened, occurs in a wide variety of habitats, but typically in wet or moist areas such as mesic prairie and in wetlands such as sedge meadows, marsh edges, and bogs. It requires full sun for optimum growth and flowering and a grassy habitat with little or no woody encroachment. Night flying hawkmoths pollinate the nocturnally fragrant flowers of this white orchid (USFWS 2012). Federally designated critical habitat has not been established for this species.

Table 3.7.2-1 Endangered and Threatened Species Recorded in LaSalle County[a]

Scientific Name	Common Name	Status[b] Federal	State
Mammals			
Myotis griescens	Gray bat	E	E
M. sodalis	Indiana bat	E	E
Birds			
Bartramia longicauda	Upland sandpiper	-	E
Dendroica cerulea	Cerulean warbler	-	T
Falco peregrinus	Peregrine falcon	-	T
Lanius ludovicianus	Loggerhead shrike	-	E
Reptiles			
Crotalus horridus	Timber rattlesnake	-	T
Emydoidea blandingii	Blanding's turtle	-	E
Amphibians			
Hemidactylium scutatum	Four-toed salamander	-	T
Fish			
Fundulus diaphanous	Banded killifish	-	T
Moxostoma carinatum	River redhorse	-	T
M. valenciennesi	Greater redhorse	-	E
Mussels			
Alasmidonta viridis	Slippershell	-	T
Elliptio dilatata	Spike	-	T
Insects			
Speyeria idalia	Regal fritillary	-	T
Plants			
Amelanchier sanguinea	Shadbush	-	E
Aster furcatus	Forked aster	-	T
Boltonia decurrens	Decurrent false aster	T	T
Carex communis	Fibrous-rooted sedge	-	T
C. plantaginea	Plantain-leaved sedge	-	E
Cornus canadensis	Bunchberry	-	E
Corydalis aurea	Golden corydalis	-	E
C. sempervirens	Pink corydalis	-	E
Dalea foliosa	Leafy-prairie-clover	E	E
Dichanthelium portoricense	Hemlock panic grass	-	E
Filipendula rubra	Queen-of-the-prairie	-	E
Luzula acuminata	Hairy woodrush	-	E
Phegopteris connectilis	Long beech fern	-	E

Table 3.7.2-1 Endangered and Threatened Species Recorded in LaSalle County[a] (Continued)

		Status[b]	
Scientific Name	**Common Name**	**Federal**	**State**
Pinus resinosa	Red pine	-	E
Platanthera leucophaea	Eastern prairie fringed orchid	T	E
Poa languida	Weak bluegrass	-	E
Sambucus racemosa pubens	Red-berried elder	-	E
Solidago sciaphila	Cliff goldenrod	-	T
Symphoricarpos albus albus	Snowberry	-	E
Veronica americana	American brooklime	-	E

[a] Source of county occurrence (except peregrine falcon): USFWS 2012 county distribution list; IDNR 2012b Illinois T&E species by county. Exelon Generation personnel have occasionally observed peregrine falcons at LSCS.
[b] E = Endangered; T = Threatened; - = Not listed

3.8 Historic and Cultural Resources

3.8.1 Regional History in Brief

The prehistory of Illinois can be broadly broken up into five different periods or cultural traditions: the Paleo-Indian period, the Archaic period, the Woodland period, the Mississippian period, and the Oneota and Protohistoric period. The Paleo-Indian period began with the migration of the earliest populations into North America. Evidence of Paleo-Indians found in Illinois includes distinct fluted projectile points and stone scrapers. Around 10,000 years before present (BP), the retreat of the continental ice sheets and changing environmental conditions marked the beginning of the Archaic period. Extending to approximately 3,000 years BP, this period is notable for development of seasonal migration patterns and an increase in the variety of natural resources incorporated in prehistoric diets. The Woodland period, from approximately 3,000 to 1,200 years BP, provides evidence for the domestication of certain plants and development of ceramics. The Mississippian period, approximately 1,200 to 700 years BP, immediately follows the Woodland and is notable for dramatic political changes. During the Mississippian period, large cities were created; the clusters of mounds that dot the Illinois landscape are evidence of these early cities. Cahokia, in Collinsville, IL, held the largest Native American population in North America. By 900 years BP, the large population centers had begun to shrink and archaeological evidence supports an outward migration of people. Evidence indicates that by 700 years BP, a small population of Native Americans unrelated to the Mississippians, known as the Oneota people, began to appear in Illinois. The Oneota consisted of small bands of hunter-farmers with distinct lithic and ceramic styles. (IHPA 1993)

French explorers began traveling down the Mississippi River into Illinois as early as 1673 (IHPA 1993). The French found the region populated by a confederation of tribes who called themselves "Hileni" or "Illiniwek" which means "men" (Fester undated). The French translated this as "Illinois." Other inhabitants of the region included tribes with similar dialects that were collectively known as the Miami family of tribes. French explorers of the time believed that the Illini and Miami people shared a common ancestry (Fester undated). The Illini Confederation and Miami family of tribes were surrounded by other powerful Native American groups that vied for land and resources such as the Fox, Winnebago, Sioux, Osage, Missouri, Chickasaw, and most notably the Iroquois Confederation (Fester undated). Competition for resources led to war among the tribes. The Illini and Miami's numbers and influence dwindled as a result of wars with other tribes, and because they sided with the French who were driven from the area by the British.

Early Euro-American settlements were generally founded along the river systems by settlers seeking to profit from the fur trade. Illinois became part of the United States territory at the close of the American Revolution. Shortly thereafter, the United States government began constructing forts in Illinois with a corresponding increase in immigration into the territory in the early 19th century. Illinois joined the Union as the 21st state in 1818. (IL SOS 2012)

The fertile soils in Illinois support a strong agricultural economy. A history of natural resource extraction, including coal mining and oil drilling, has also supported the local economies across the state. Illinois has the fifth largest state population in the country. (IL SOS 2011)

3.8.2 Pre-construction Known Historic and Archaeological Resources

Historically, the land occupied by LSCS was used primarily for agriculture. Settlement was slow along the southern margin of the Illinois River Valley; the oldest historic sites are located near the prairie-forest ecotone and isolated wetland depressions or springs. Historic farmsteads in the area are consistent with the trend noted throughout the Prairie Peninsula of early farmers settling along the ecotone and accessing the forest for wood for fuel and building materials, using the prairie as open range for cattle, and plowing the more easily tillable forest soils with newly introduced steel-tipped plows. Historical sites are in very different locations compared to prehistoric sites. Whereas prehistoric sites are found along rivers, historic sites are predominantly in the uplands.

Based on the results of Exelon Generation's 2013 search of the Illinois State Archaeological Site Files, a proprietary database maintained by the Illinois State Historic Preservation Office (SHPO) and open only to cultural resource professionals, the Illinois Archaeological Survey (IAS) completed a Phase I Archaeological Survey of the LSCS site (originally proposed as the Collins Generating Station) in 1972 and concluded that the construction of the facility would have no significant impact on archaeological resources. The findings apparently were reported by Stuever in a 1972 report that has been lost[2]. Locations LS00207, LS00208, and LS00209 were three of five isolated finds identified in the 1972 survey. At the time of the Phase I survey, IAS did not recognize isolated finds as sites, and the isolated finds were not recorded or assigned IAS accession numbers. Because isolated finds LS00207, LS00208, and LS00209, by definition, were not eligible for inclusion on the NRHP, they were not evaluated. The NRC's Final Environmental Statement relating to the operation of LSCS, which was published in November 1978 (NUREG-0486), stated that "[t]here are no historical and cultural sites recorded in the National Registry of National Landmarks, as supplemented 8 June 1976, or the National Register of Historic Places, as supplemented 3 January 1978, located on the LaSalle County Station site."

3.8.3 Post-Construction Known Historical and Archaeological Resources

For this Environmental Report, the National Register Information System (NRIS) on-line database was used to locate historic properties listed on the National Register of Historic Places (NRHP) within a 10 km (6-mi) radius of LSCS. Seven properties listed on the NRHP were identified (Table 3.8-1).

In 1993, the Illinois State Museum Society (ISMS) contracted with the Illinois Department of Military Affairs to document and analyze prehistoric and historic cultural resources in the Marseilles Training Area, which is located immediately northwest of LSCS, and is used by the Illinois Army Reserve National Guard (Ferguson, et al. 1995). A portion of the Marseilles Training Area intersects the right-of-way for the LSCS makeup and blowdown pipelines and is leased to the National Guard by Exelon Generation. Fieldwork was conducted during 1993-1994. The ISMS previously conducted a survey in portions of the project area in 1983, the results of which are discussed in the Ferguson, et al. 1995 report. Forty-eight prehistoric archaeological sites were found in the project area during the 1993-1994 survey, including sites LS00514 and LS00533. Site LS00252 was one of 44 sites previously documented by the ISMS during the 1983 survey. Sites LS00252, LS00514, and LS00533 were not determined NRHP-eligible (Table 3.8-2).

The search of the Illinois State Archaeological Site Files identified 146 previously recorded archaeological sites within 10 km (6 mi) of LSCS. Six sites are on LSCS property, including the three isolated finds identified in the 1972 survey discussed above. The remaining three sites were identified in archaeological surveys conducted during 1974-1975 for LSCS's transmission and pipeline corridors and during 1983 and 1993-1994 for the Marseilles Training Area (Struever 1975; Ferguson, et al. 1995). No additional archaeological resources have been

[2] Exelon Generation ascertained this information from extant reports at the Illinois SHPO and from information in the LSCS operating license stage FES (NRC 1978)

recorded on the LSCS property since the completion of these surveys. Table 3.8-2 lists the known archaeological resources on the LSCS property.

Table 3.8-1 Sites listed on National Register of Historic Places within approximately 6 mi (10 km) of LSCS

Site Name/Number	Address	City, County	Distance from LSCS (km [mi])
Sacred Heart Church (NR165052)	221 W. Emmet St.	Kinsman, Grundy	10.2 (6.3)
Hay Barn (NR165106)	2319 N. 14th Rd.	Streator, LaSalle	12.4 (7.7)
Ransom Water Tower (NR200859)	Plumb St.	Ransom, LaSalle	9.7 (6.0)
Marseilles Hydro Plant (NR200999)	Commercial St.	Marseilles, LaSalle	9.8 (6.0)
Armour's Warehouse (NR201063)	William & Bridge Sts.	Seneca, LaSalle	9.0 (5.6)
Rock Island & Pacific Railroad Depot (NR201098)	151 Washington St.	Marseilles, LaSalle	10.4 (6.5)
Illinois & Michigan Canal (NR200462)	U.S. 6 in Channahon State Park	Lockport to LaSalle-Peru; Will, Grundy, LaSalle	7.8 (4.7)

Table 3.8-2 Archaeological Sites located within the LSCS Property

Site Name/Number	Site Types	NRHP Eligibility
LS00207/ Collins Station Site #1	Unknown Prehistoric	Isolated, Not Eligible
LS00208/ Collins Station Site #2	Unknown Prehistoric	Isolated, Not Eligible
LS00209/ Collins Station Site #3	Unknown Prehistoric	Isolated, Not Eligible
LS00252	Unknown Prehistoric	Not Eligible
LS00514/ Boog Powell	Unknown Prehistoric	Not Eligible
LS00533	Unknown Prehistoric	Not Eligible

3.9 Socioeconomics

Workforce

LSCS has a workforce of approximately 910 employees, 57 percent of whom live in LaSalle County, 17 percent in Grundy County, and 12 percent in Will County. The remaining 14 percent reside in 21 additional Illinois counties and 4 states (Tetra Tech Undated). Roads on which the workers commute are described in Section 2.5. Although Level of Service evaluations, as defined by the Transportation Research Board, are not available, the LaSalle County Highway Department states that the roads near the Station that are most affected by commuting Station workers are free flowing (Kinzer 2013).

Transient Population

Table 3.9-1 identifies recreational areas located within an approximately 16-km (10-mi) radius of LSCS and provides the typical number of visitors to each area (Arcadis 2012).

Property Taxes

Property taxes paid on LSCS are based partially on settlement agreements for the valuation of the power block, with the remaining land taxed on the assessment of fair market value, as established by Illinois law. Power block tax payments are typically approximately 98 percent of the total Station tax payment. A 1999 settlement agreement covered the years 2000 through 2004, and a 2006 settlement agreement covered the years 2005 through 2008. Although negotiations for a settlement agreement for 2009 and subsequent years began in 2009, they were not completed until mid-2013. Therefore, as shown in Table 3.9-2, there was a sharp increase in property taxes based on assessments of the power block by the County Assessor, as affirmed or amended on appeal by the LaSalle County Board of Review. Exelon Generation appealed the assessment for each of the tax years 2009, 2010, 2011, and 2012 to the Illinois Property Tax Appeal Board because the Company does not believe these assessments reflect an accurate valuation of the plant based on independent appraisals commissioned by Exelon Generation. In July 2013, Exelon Generation and all the taxing bodies for the power block agreed to a new long-term settlement agreement which sets the Equalized Assessed Value of the plant for the next seven years, starting with the 2013 tax year. This settlement agreement was fully executed and approved by the Court for the 13th Judicial District in LaSalle County, Illinois in February 2014. At the request of all parties, the Property Tax Appeal Board dismissed the appeals with prejudice in May 2014.

The taxes paid to the local taxing bodies most recently constitute between 94 percent and less than 1 percent of the total levy for any individual taxing body, as reflected in Table 3.9-3. Exelon Generation expects the taxes under the new settlement agreement to continue at similar percentages of the total levies for these taxing bodies.

In the GEIS, the NRC determined that impacts to socioeconomics from continued plant operations over the license renewal term would be SMALL for all nuclear plants, and designated these Category 1 issues (NRC 2013b). Because the new and significant analysis identified no information regarding LSCS that would change the conclusions of the GEIS regarding socioeconomics, no further analyses are required.

Table 3.9-1 Recreational Facilities near LSCS and Daily Occupancy

Facility Name	Low Occupancy	High Occupancy
Seneca Yacht Club	0	100
LaSalle Lake	0	450
Marseilles Boat Club	0	32
Spring Brook Marina	0	450
Black's Marina	0	150
Troll Hollow Campground	0	150
Illini State Park	0	2,000
Marseilles State Fish and Wildlife Area[1]	0	20
Camp Pokanoka	0	120
Woodsmoke Ranch	0	1,500
Four Star Campground	0	690
Glenwood Farms Campground	0	400
Mariners Village and Marina	0	348
Seneca Hunt Club[1]	10	50

Source: Arcadis 2012
[1]Low Occupancy is typically a winter weekday. For the Marseilles State Fish and Wildlife Area, and the Seneca Hunt Club, low occupancy occurs in the summer.

Table 3.9-2 LSCS Power Block Tax Payments and Valuations

Tax Year	Equalized Assessed Value	Inferred Fair Market Value of Real Estate	Taxes Paid by Exelon Generation
2007	$ 235,000,000 Under settlement agreement	$ 1,566,700,000	$ 12,258,540
2008	$ 235,000,000 Under settlement agreement	$ 1,566,700,000	$ 12,181,812
2009	$ 525,000,000 Set by Board of Review	$ 3,571,500,000	$ 24,595,282
2010	$ 525,000,000 Set by Board of Review	$ 3,571,500,000	$ 24,652,781
2011	$ 504,000,000 Set by Board of Review	$ 3,360,000,000	$ 23,888,466
2012	$ 488,250,000 Set by Board of Review	$ 3,255,000,000	$ 23,383,171

Table 3.9-3 LSCS Tax Payments to Taxing Entities as a Percentage of Total Levy

Taxing Entity	2008 Exelon Generation Payment ($)	2008 Total Levy ($)	2008 (% of total levy)	2009 Exelon Generation Payment ($)	2009 Total Levy ($)	2009 (% of total levy)
Brookfield Township	69,461	76,652	91	76,252	80,927	94
Brookfield Township Road	357,366	394,365	91	390,794	414,758	94
South Prairie Park	30,657	35,117	87	32,301	35,152	92
Allen-Brookfield	12,984	14,945	87	33,420	36,459	92
Seneca Fire-Ambulance	217,350	268,382	81	397,326	506,083	78
Seneca Grade School # 170	3,706,890	4,746,421	78	6,826,561	7,770,131	88
Seneca Library	428,454	595,764	72	538,263	641,743	84
Seneca High School # 160	4,306,545	5,991,958	72	9,393,976	11,196,091	84
Marseilles Fire	214,335	440,770	49	333,623	496,726	67
IVCC # 513	854,878	7,264,843	12	1,817,960	8,116,921	22
LaSalle County	2,244,325	21,126,061	11	4,988,649	24,402,614	20
Allen Fire	9,039	107,671	8	7,435	118,494	6
Allen Township	2,702	35,420	7	3,392	60,698	5
Allen Township Road	3,883	50,259	7	3,620	64,768	5
Allen Township School # 65	23,535	519,823	4	19,236	553,462	3
Streator High School # 40	3,711	5,422,715	< 1	3,740	5,758,743	< 1
Village of Ransom	148	37,731	< 1	138	35,658	< 1
Ottawa High School # 140	278	13,679,106	< 1	278	13,976,284	< 1
Grand Ridge School # 95	358	1,848,337	< 1	358	2,100,855	< 1
Reddick Library	27	1,070,996	< 1	28	1,128,193	< 1
City of Marseilles	616	952,995	< 1	652	1,020,184	< 1
Marseilles Library	52	81,931	< 1	52	82,859	< 1

Table 3.9-3 LSCS Tax Payments to Taxing Entities as a Percentage of Total Levy (Continued)

Taxing Entity	2010 Exelon Generation Payment ($)	2010 Total Levy ($)	2010 (% of total levy)	2011 Exelon Generation Payment ($)	2011 Total Levy ($)	2011 (% of total levy)
Brookfield Township	79,443	84,382	94	76,363	81,298	94
Brookfield Township Road	409,928	433,687	95	408,205	432,781	94
South Prairie Park	32,307	35,277	92	32,030	35,133	91
Allen-Brookfield	33,426	37,439	89	33,770	38,014	89
Seneca Fire-Ambulance	415,772	531,867	78	430,993.00	557,538.00	77
Seneca Grade School # 170	6,738,777	7,686,790	88	6,571,088	7,535,946	87
Seneca Library	561,694	672,365	84	583,091	702,928	83
Seneca High School # 160	9,403,569	11,260,512	84	9,027,046	10,894,077	83
Marseilles Fire	354,721	522,132	68	361,667	536,186	67
IVCC # 513	1,863,375	8,302,630	22	1,794,896	8,137,831	22
LaSalle County	4,998,537	24,438,314	20	4,805,338	23,879,332	20
Allen Fire	5,013	141,408	3	4,732	135,170	3
Allen Township	2,697	90,024	3	2,740	92,576	3
Allen Township Road	3,920	127,037	3	3,933	129,061	3
Allen Township School # 65	18,667	908,100	2	19,329	952,396	2
Streator High School # 40	3,643	5,949,509	< 1	3,626	5,890,354	< 1
Village of Ransom	154	44,469	< 1	159	45,553	< 1
Ottawa High School # 140	281	13,787,339	< 1	283	13,446,103	< 1
Grand Ridge School # 95	363	2,280,626	< 1	362	2,287,341	< 1
Reddick Library	29	1,145,974	< 1	30	1,115,380	< 1
City of Marseilles	653	1,053,533	< 1	644.00	1,038,222	< 1
Marseilles Library	52	82,117	< 1	52	81,294	< 1

Table 3.9-3 LSCS Tax Payments to Taxing Entities as a Percentage of Total Levy (Continued)

Taxing Entity	2012 Exelon Generation Payment ($)	2012 Total Levy ($)	2012 (% of total levy)
Brookfield Township	76,315	81,264	94
Brookfield Township Road	408,232	432,951	94
South Prairie Park	31,974	35,141	91
Allen-Brookfield	34,603	39,022	89
Seneca Fire-Ambulance	488,789	635,663	77
Seneca Grade School # 170	6,386,426	7,340,894	87
Seneca Library	605,222	732,158	83
Seneca High School # 160	8,763,547	10,617,796	82
Marseilles Fire	373,647	548,440	68
IVCC # 513	1,746,407	7,896,139	22
LaSalle County	4,707,140	23,252,266	20
Allen Fire	5,055	144,143	3
Allen Township	2,748	92,677	3
Allen Township Road	3,935	128,922	3
Allen Township School # 65	19,333	1,023,665	2
Streator High School # 40	3,618	5,863,251	< 1
Village of Ransom	165	46,140	< 1
Ottawa High School # 140	285	12,661,994	< 1
Grand Ridge School # 95	363	2,266,428	< 1
Reddick Library	31	1,062,337	< 1
City of Marseilles	678	1,050,103	< 1
Marseilles Library	52	78,582	< 1

3.10 Human Health

3.10.1 Microbiological Hazards

As discussed in Section 2.2, LSCS uses a cooling pond for condenser cooling. Under an NPDES permit (Appendix C), the Station continually releases blowdown water from the cooling pond to the Illinois River to prevent the buildup of salts and solids in the cooling pond. Most of the cooling pond is managed by the Illinois Department of Natural Resources as a recreational resource that is open to the public for fishing from approximately mid-March through mid-October. Some areas of the cooling pond are off-limits to the public; these areas are clearly marked with either buoys or signs. Swimming, wading, water skiing, and sailing are not allowed.

The license renewal GEIS (NRC 2013b) discusses microbiological hazards around nuclear power plants, including background information, results of studies of microbiological hazards in cooling towers, hazards to plant workers, and hazards to members of the public. The discussion of specific hazards focuses on the thermophilic microorganisms, *Legionella* spp. and *Naegleria fowleri*, which can be a hazard, respectively, in cooling towers and cooling water discharge. There have been no Exelon Generation or state studies done to determine the presence of these microorganisms in waters influenced by LSCS.

Legionella can be a hazard to plant workers performing maintenance in cooling towers and on condenser tubes. Although LSCS does not use cooling towers, condenser tube maintenance may occur. Plant workers cleaning condenser tubes are protected by a plant procedure that provides a standard methodology for identifying industrial hazards prior to performance of jobs. Under this procedure, possible factors that may influence safe execution of the job, including chemical and biological hazards, would be considered and appropriate worker protection measures would be designated for use during performance of the work. Exposure of members of the public to *Legionella* from LSCS operations would not be expected because there is no opportunity for these pathogens to be sufficiently concentrated at expected exposure points.

Naegleria fowleri in heated plant effluent can be a hazard to recreational water users. Potential for exposure by recreational users exists in the cooling pond and in the discharge to the Illinois River. *Naegleria* infection is the cause of primary amebic meningoencephalitis, an extremely rare disease that is usually fatal: only 28 cases involving recreational surface water were reported in the entire US from 2003 to 2012 (CDC 2013).

The GEIS (NRC 2013b) states that *Naegleria* is rarely found in water cooler than 35°C (95°F), but it thrives in temperatures ranging from 35°C (95°F) to 41°C (106°F) or higher. During 2011 and 2012, the highest maximum daily temperatures in the cooling pond discharge to the Illinois River occurred in August and were 37°C (99°F) and 38°C (101°F), respectively (Exelon Nuclear 2011b; Exelon Nuclear 2012b). LSCS's NPDES permit allows a zone of mixing in the river and limits the temperature at the edge of the mixing zone to less than 5°F higher than the ambient river temperature. Furthermore, the temperature beyond the mixing zone cannot exceed specified monthly limits for longer than 1 percent of any 12-month period, and cannot at any time exceed the specified monthly limit by more than 1.7°C (3°F). The specified limit in August is 32°C (90°F). Hence, in extremely hot weather, plant operations must be adjusted, if necessary, to assure that the river temperature outside the mixing zone does not exceed 34°C (93°F) (See Special Condition C of the NPDES permit, Appendix C). A 2009 Exelon Generation thermal evaluation indicates that the average August river temperature is 24.7°C (76.5°F) (Exelon Nuclear 2009b) and that well-mixed river water temperatures would not approach the permit limits at any time (Exelon Nuclear 2009b).

While exposure of the public to *Naegleria* is possible in the mixing zone, the probability of such exposure is very low because of (1) the small area of the mixing zone compared to that of the river in the discharge area, (2) the limited time allowed in the permit in which heated effluent can be above critical temperatures. Additionally, the Illinois Department of Public Health stated that (as of June 2013) there has never been a case of *Naegleria* infection reported in Illinois (IDPH 2013b).

Because the cooling pond is used by the public in the hot summer months and its temperatures are higher than river temperatures, there is greater potential for *Naegleria* infection in the cooling pond than in the river. The FES (NRC 1978) conservatively calculated cooling pond temperatures ranging from 33°C (92°F) to 47°C (116°F). However, because *Naegleria* infection occurs through the nose and activities that could result in immersion in the cooling pond, such as swimming and water skiing, are prohibited, the probability of infection is low. Inhalation of aerosols raised by motors would be the most likely method of infection. Nevertheless, as previously stated, there have been no *Naegleria* infections reported in Illinois. Therefore, the probability of infection is clearly low.

3.10.2 Electric Shock Hazards

The onsite switchyard at LSCS connects the Station to the regional transmission system through four 345-kilovolt transmission lines and two 138-kilovolt transmission lines. Two of the 345-kilovolt transmission lines terminate at Plano substation and two terminate at Braidwood Station. One of the 138-kilovolt transmission lines terminates at Streator substation and the other terminates at Mazon substation. The switchyard also supplies power to LSCS from the grid. The LSCS switchyard is a permanent part of the overall transmission system and would remain in service even if LSCS was retired. Therefore, the six transmission lines connected to the LSCS switchyard are not in-scope transmission lines as defined by footnote 4 of Table B-1 of 10 CFR Part 51, Subpart A. The electrical connections between the main plant and the LSCS switchyard are plant components that traverse only property used for industrial purposes. No rights-of-way are maintained specifically for these components, and electrical shock hazards are controlled on the LSCS site in accordance with applicable industrial safety standards.

3.10.3 Radiological Hazards

Some workers at LSCS are classified as radiological workers and, depending on their work assignments, receive occupational radiation exposure. NRC regulations at 10 CFR Part 20 limit the annual total effective dose equivalent (TEDE) for individual radiation workers to 0.05 Sieverts (5 rem) per year; however, LSCS procedures administratively limit the exposure below NRC's regulatory limit.

The three-year average (2009 to 2011) collective TEDE (sum of dose for all exposed workers) for LSCS is approximately 1.7 person-Sievert (170 person-rem) per reactor. This value can be compared to the national average collective dose for all boiling water reactors (BWRs) of approximately 1.43 person-Sievert (143 person-rem) for the same three-year period (NRC 2013d). Although NRC requires nuclear plants to keep collective doses as low as reasonably achievable (ALARA), there is no regulatory limit on collective dose.

The average TEDE per LSCS worker over this period (2009 to 2011) was 1.42 millisievert (142 millirem) compared to 1.35 millisievert (135 millirem) for all BWRs. The average TEDE per megawatt generated per year was 1.60 millisievert (160 millirem) for both LSCS and the national average for BWRs. (NRC 2013d)

LSCS is not planning to undergo refurbishment for the license renewal term. There are no expected increases in either occupational or public radiation exposure because of license renewal. Data from NRC (NRC 2013b) indicate that LSCS occupational radiation exposures fall within the range of those for other operating BWRs.

In the GEIS, the NRC determined that impacts of occupational radiation exposure from continued plant operations over the license renewal term would be SMALL for all nuclear plants, and designated such exposures as a Category 1 issue (NRC 2013b). Because the new and significant analysis identified no information regarding LSCS that would change the conclusions of the GEIS regarding occupational radiation exposure, no further analyses are required.

In the GEIS, the NRC determined that impacts of radiation exposure to the public from continued plant operations over the license renewal term would be SMALL for all nuclear plants, and designated such exposures as a Category 1 issue (NRC 2013b).

LSCS samples surface water, groundwater, fish, air, milk and food products monthly and reports the results annually in the Radiological Environmental Operating Report. The purpose of the sampling program is to evaluate the relationship between the quantities of radioactive materials released from LSCS and the resulting radiation dose to individuals from the principle exposure pathways – air, direct contact with water, and ingestion of water and food. Based on the amount of radiation released to the environment, and its occurrence in the principle exposure pathways, the consistent conclusion of the annual Radiological Environmental Operating Reports is that the operation of LCSC has never had adverse radiological impacts on the environment or the public (see for example Exelon Generation 2014). Because the new and significant analysis identified no information regarding LSCS that would change the conclusions of the GEIS regarding occupational radiation exposure, no further analyses are required.

3.11 Environmental Justice

NRC has concluded that an 80-km (50-mi) radius could reasonably be expected to experience potential environmental impacts from license renewal activities. For environmental justice analyses, the NRC methodology uses the state or states which have land within the 80-km (50-mi) radius of the nuclear plant seeking license renewal as the baseline(s) for comparative analysis (NRC 2009). Exelon Generation has used this approach for identifying the minority and low-income populations that could be affected by LSCS operations.

Exelon Generation used ArcGIS® geographic information system software to determine the minority and low-income characteristics by census block group. Exelon Generation included any census block group in the analysis if any part of the block group was within 80 km (50 mi) of LSCS. The 80-km (50-mi) radius includes 1,264 block groups (Table 3.11-1) (Tetra Tech 2013a).

3.11.1 Minority Populations

The NRC Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues (NRC 2009) defines a "minority" population as: American Indian or Alaskan Native; Asian; Native Hawaiian or other Pacific Islander; Black Races, and Hispanic Ethnicity. Additionally, NRC's guidance requires that (1) all other single minorities are to be treated as one population and analyzed, (2) multi-racial populations are to be analyzed, and (3) the aggregate of all minority populations are to be treated as one population and analyzed. The guidance indicates that a minority population exists if either of the following two criteria is met:

- The minority population in a U.S. Census Bureau (USCB) block group or environmental impact site exceeds 50 percent.
- The minority population percentage of the block group or environmental impact area is significantly greater (typically at least 20 percentage points) than the minority population percentage in the baseline area chosen for comparative analysis.

For each of the 1,264 block groups within the 80-km (50-mi) radius, Exelon Generation calculated each minority's percent of the block group's population. If any minority percentage exceeded 50 percent of the block group population, then the block group was identified as having a minority population. Exelon Generation used the entire state of Illinois as the baseline area for comparative analysis, and calculated the percentages of each minority category in Illinois. If any block group percentage exceeded the state percentage by more than 20 percent, then a minority population was determined to exist (Tetra Tech 2013a).

Census data for Illinois (Tetra Tech 2013a) characterizes 0.3 percent of the state's population as American Indian or Alaskan Native; 4.6 percent Asian; 0.0 percent Native Hawaiian or other Pacific Islander; 14.5 percent Black races; 6.7 percent all other single minorities; 2.3 percent multi-racial; 28.5 percent aggregate of minority races; and 15.8 percent Hispanic ethnicity.

Table 3.11-1 presents the numbers of block groups, by county, within the 80-km (50-mi) radius that exceed either, or both, of the thresholds for minority populations. Figures 3.11-1 through 3.11-5 locate the minority block groups within the 80-km (50-mi) radius. Within the 80-km (50 mi) radius, the numbers of census block groups meeting one or both criteria for populations of concern were as follows:

- 49 (3.9 percent) had Black races minority populations;

- 19 (1.5 percent) had Asian minority populations;
- 60 (4.7 percent) had All Other Single Minority populations;
- 105 (8.3 percent) had Aggregate Minority populations;
- 128 (10.1 percent) had Hispanic Ethnicity populations.

3.11.2 Low-Income Populations

NRC guidance defines low-income population based on statistical poverty thresholds (NRC 2009) if either of the following two criteria is met:

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

Exelon Generation calculated the percentage of low-income households in each census block group and in the state of Illinois. The percentage of low-income households in Illinois is 11.9 percent (Tetra Tech 2013a). Table 3.11-1 identifies the low-income block groups with the 80-km (50-mi) radius of LSCS. Figure 3.11-6 locates the low-income block groups.

Within the 80-km (50-mi) radius, 32 census block groups (2.5 percent) meet one or both criteria for low-income households.

3.11.3 Subsistence-Like Populations and Migrant Workers

Exelon Generation queried LSCS staff, government organizations with a social welfare mission, and private social welfare organizations to identify whether there are any subpopulations near LSCS (LaSalle and Grundy counties) that engage in a subsistence-like lifestyle. This would include groups in which hunting, gathering, fishing, and gardening constituted a larger fraction of the subpopulations food sources than those of the general population. No such subpopulations were identified (Tetra Tech 2014).

The U.S. Department of Agriculture 2012 census (USDA 2014b) reports that LaSalle County has 526 farms that employ hired laborers for a total hired workforce of 1,295. Of these, eight farms use 35 migrant workers. In Grundy County, 144 farms hire 340 workers, with no farms hiring migrant workers.

Table 3.11-1 Minority and Low-Income Population Census Block Groups within 80-km (50-mi) of LSCS

County (all in Illinois)	**County Number**	**Number of Block Groups within 80 km (50 mi)**[a]	**Black**[b]	**American Indian or Alaskan Native**[b]	**Asian**[b]	**Native Hawaiian or other Pacific Islander**[b]	**Some Other Race**[b]	**Multi-Racial**[b]	**Aggregate**[b]	**Hispanic**[b]	**Low-Income Households**[b]
Bureau	11	33	0	0	0	0	1	0	0	2	0
Cook	31	54	4	0	0	0	0	0	3	0	0
DeKalb	37	48	1	0	0	0	0	0	1	1	8
DuPage	43	215	2	0	17	0	7	0	8	12	1
Ford	53	6	0	0	0	0	0	0	0	0	2
Grundy	63	34	0	0	0	0	0	0	0	0	0
Iroquois	75	10	0	0	0	0	0	0	0	1	0
Kane	89	160	1	0	0	0	41	0	31	61	0
Kankakee	91	74	15	0	0	0	0	0	16	2	9
Kendall	93	39	0	0	0	0	0	0	0	1	0
LaSalle	99	105	1	0	0	0	0	0	0	5	3
Lee	103	14		0	0	0	0	0	0	0	0
Livingston	105	35	1	0	0	0	0	0	0	0	1
McLean	113	16	0	0	0	0	0	0	0	0	0
Marshall	123	12	0	0	0	0	0	0	0	0	0
Ogle	141	4	0	0	0	0	0	0	0	2	0
Peoria	143	7	0	0	0	0	0	0	0	0	0
Putnam	155	8	0	0	0	0	0	0	0	0	0
Tazewell	179	1	0	0	0	0	0	0	0	0	0
Will	197	365	24	0	2	0	11	0	46	41	8
Woodford	203	24	0	0	0	0	0	0	0	0	0
	Totals	1264	49	0	19	0	60	0	105	128	32

Table 3.11-1 Minority and Low-Income Population Census Block Groups within 80-km (50-mi) of LSCS (Continued)

County (all in Illinois)	**County Number**	**Number of Block Groups within 50-Miles**[a]	**Black**[b]	**American Indian or Alaskan Native**[b]	**Asian**[b]	**Native Hawaiian or other Pacific Islander**[b]	**Some Other Race**[b]	**Multi-Racial**[b]	**Aggregate**[b]	**Hispanic**[b]	**Low-Income Households**[b]
Illinois State Percentages			14.5	0.3	4.6	0.0	6.7	2.3	28.5	15.8	11.9

Note: Highlighted counties are entirely within the 80-km (50-mi) radius.

People living in the following types of institutions/facilities on the date of the Census are counted as living at the institution/facility of residence rather than at any other former residence (USCB 2010):

- Correctional facilities (e.g., federal/state/local prisons, confinement/detention centers);
- Non-correctional facilities (e.g., adult/juvenile group homes, residential treatment centers, shelters);
- Long term medical facilities (e.g., psychiatric care facilities, nursing facilities); and
- Housing for students living away from their parental home (on- or off-campus).

[a] Entries denote numbers of census block groups

[b] Entries denote state percentages of race, ethnicity, and low-income households.

Source: Tetra Tech 2013a

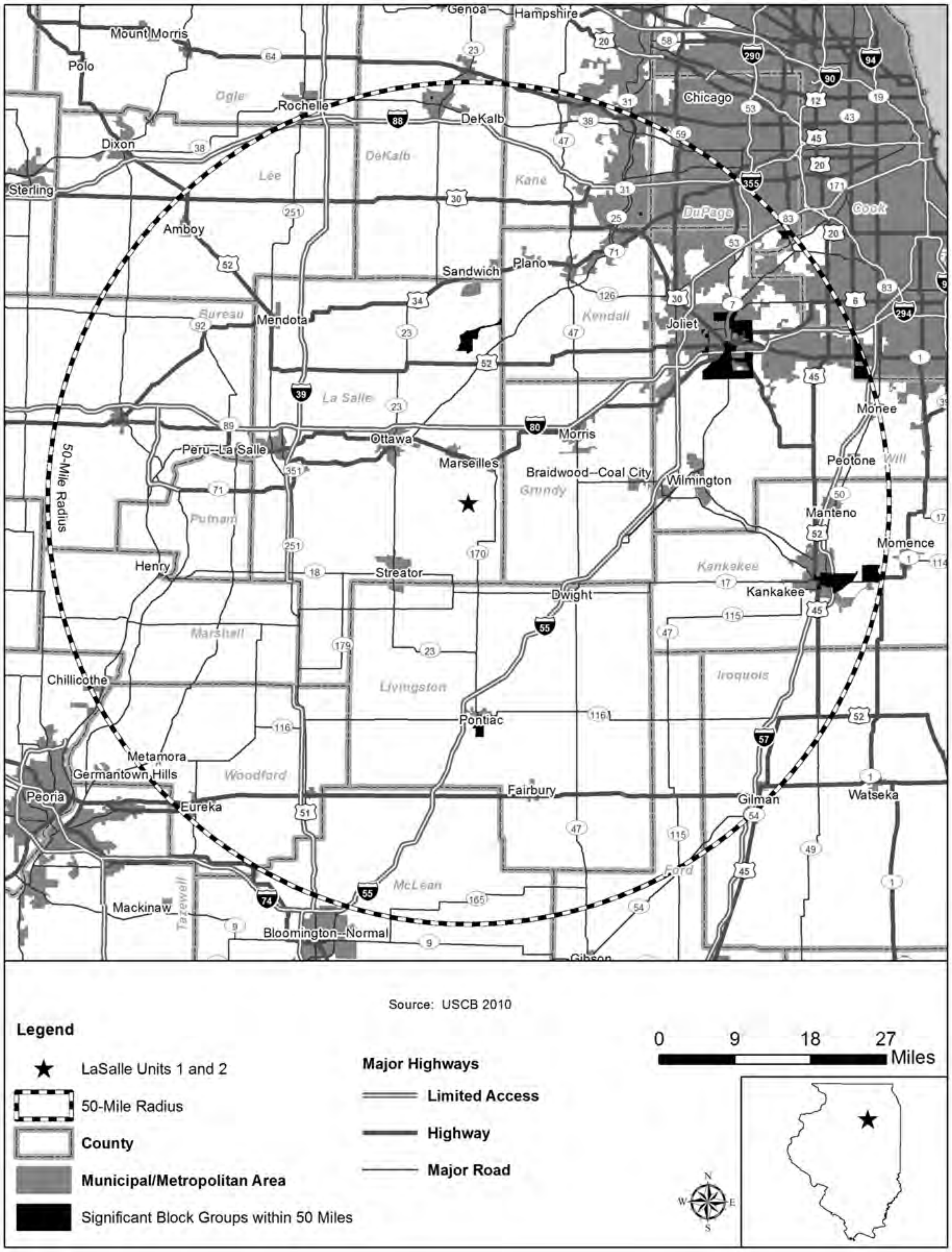

Figure 3.11-1 Black Minority

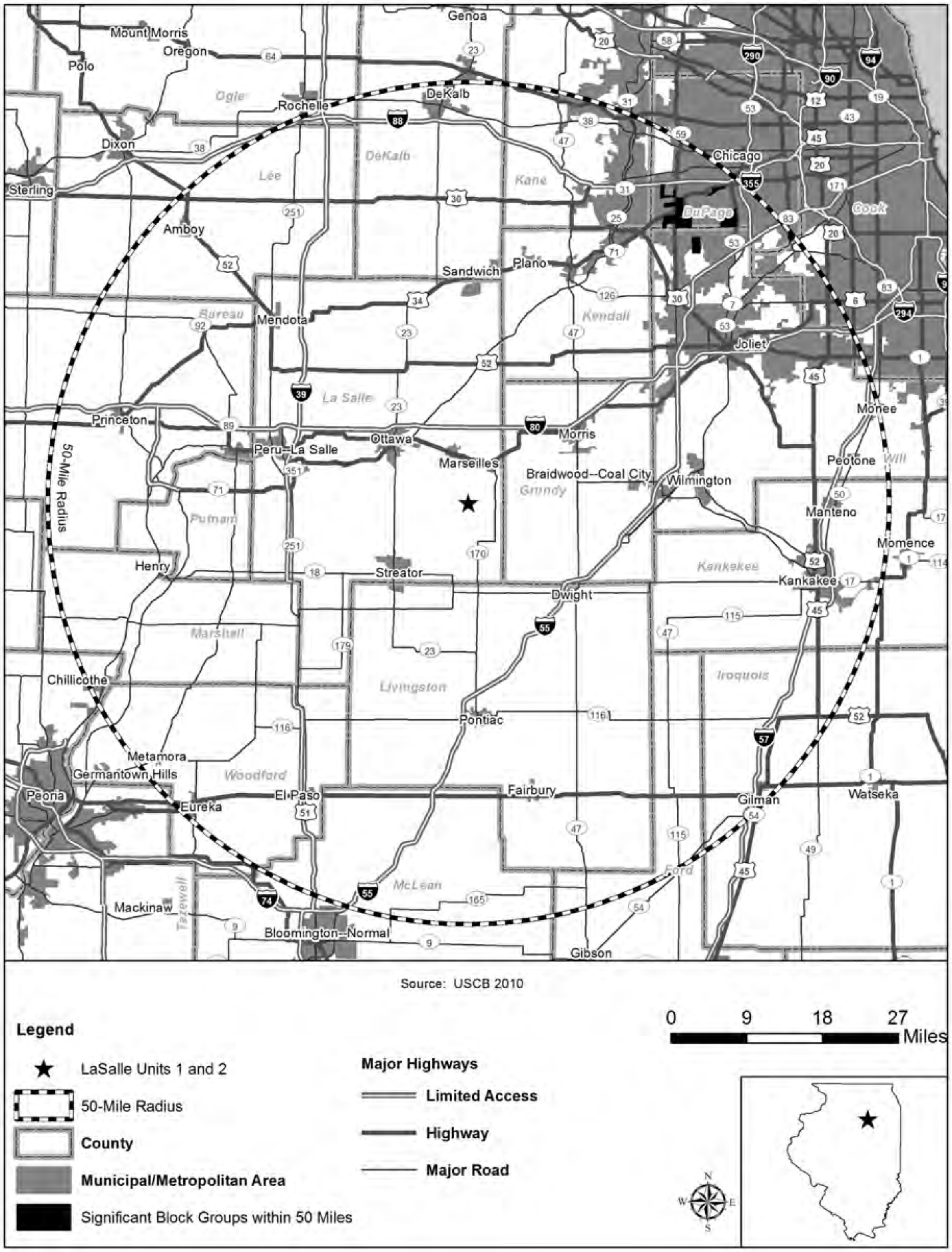

Figure 3.11-2 Asian Minority

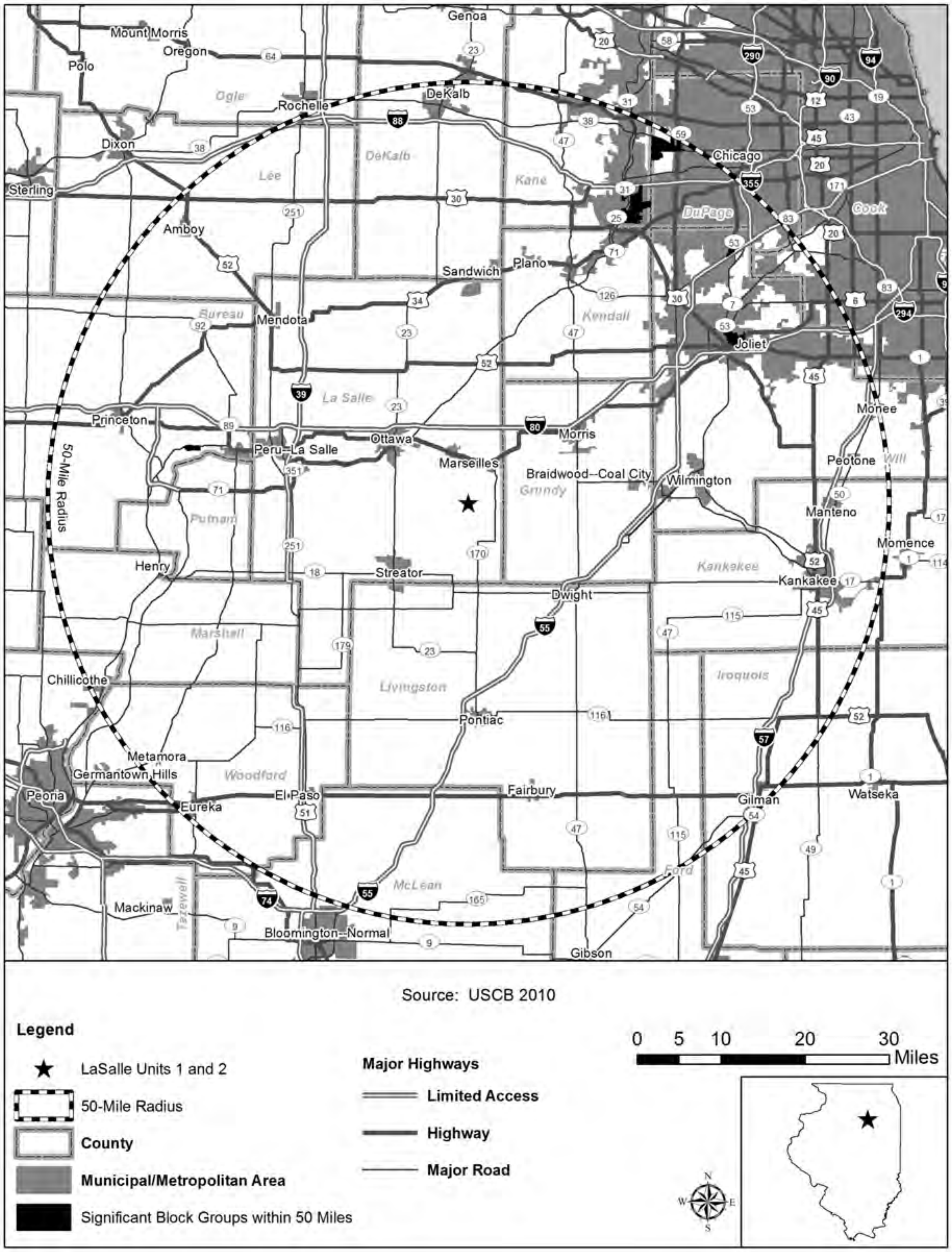

Figure 3.11-3 Other Minority

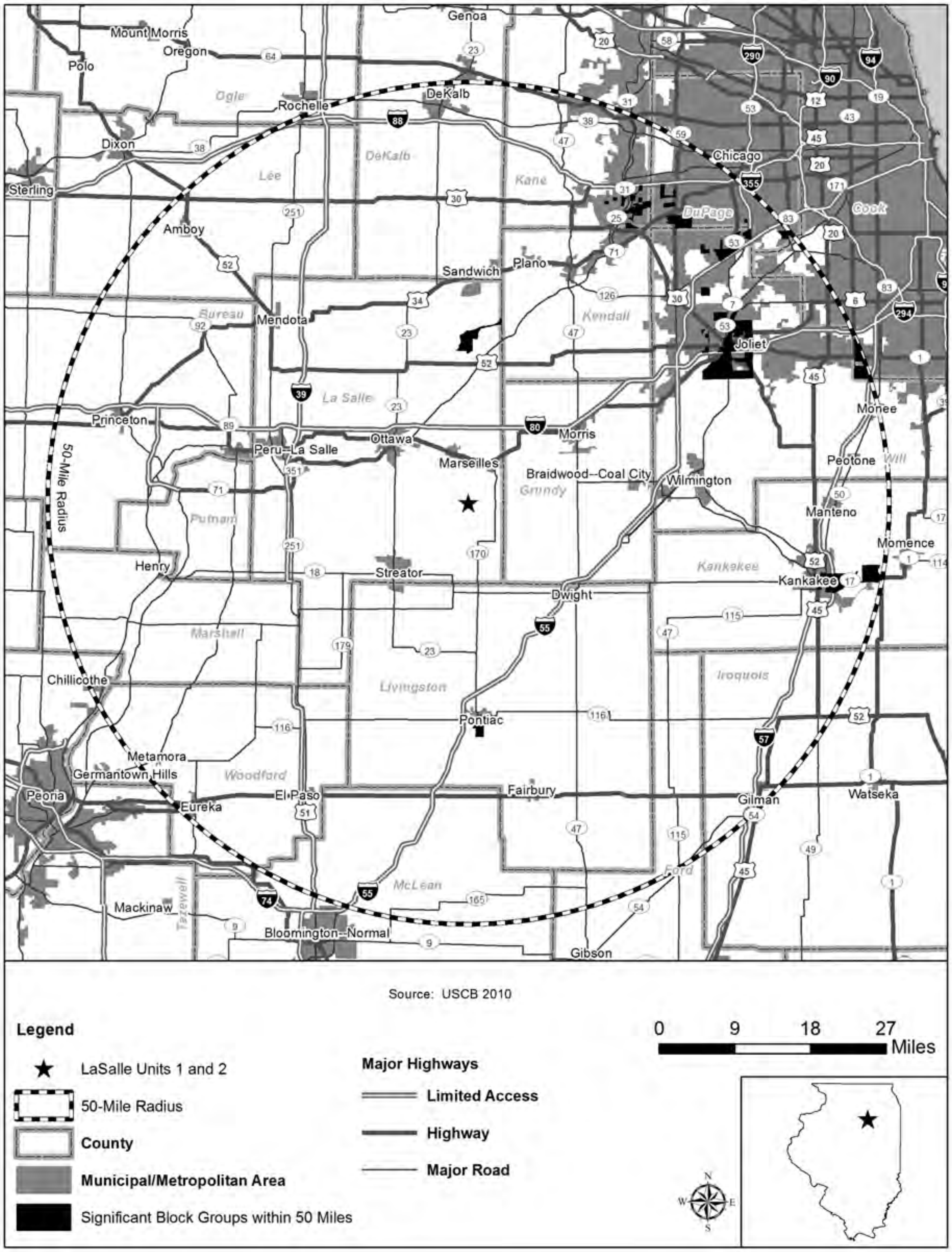

Figure 3.11-4 Aggregate of Races

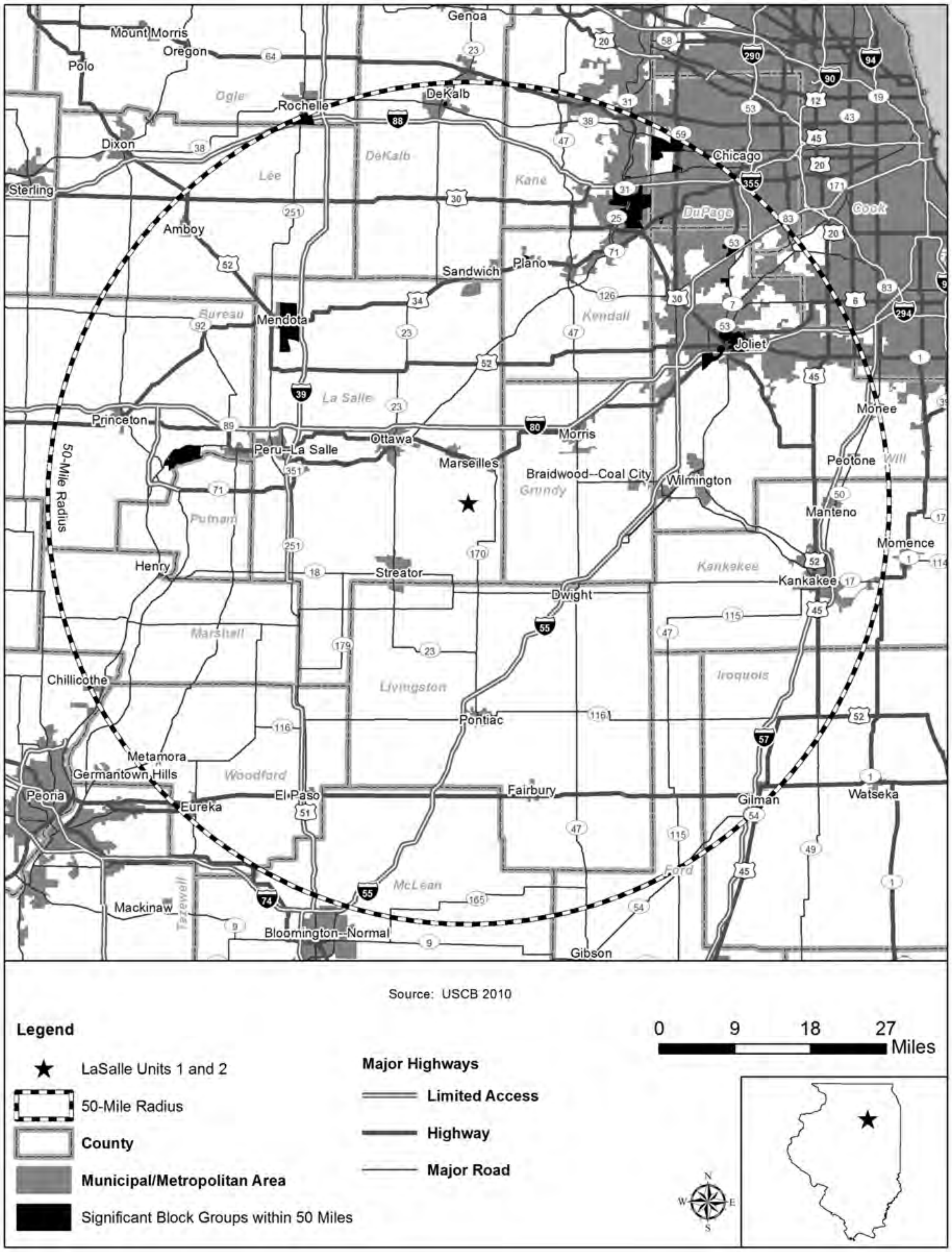

Figure 3.11-5 Hispanic Ethnicity

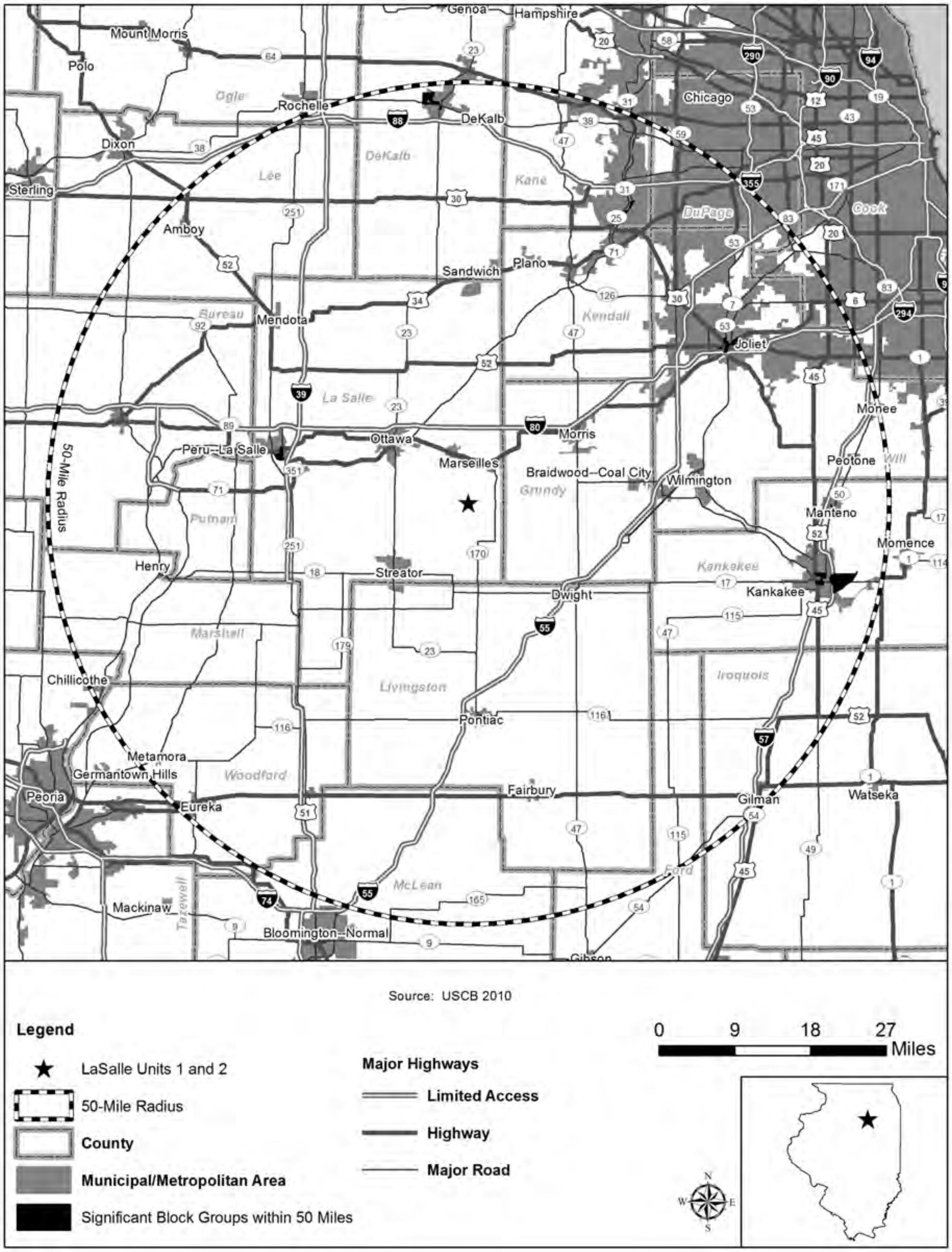

Figure 3.11-6 Low Income Household

3.12 Waste Management

Section 2.2.7 of this Environmental Report describes the radioactive waste management systems.

Section 2.2.8 describes the non-radioactive waste management systems. As stated in Section 2.2.8, all non-radioactive wastes are managed according to state and federal regulations, and Exelon Generation procedures.

Exelon Generation has identified no new and significant information related to waste management at LSCS. Accordingly, no further assessment of waste management impacts has been performed.

Chapter 4

Environmental Consequences of the Proposed Action and Mitigating Actions

NRC

> **"The report must contain a consideration of alternatives for reducing adverse impacts…for all Category 2 license renewal issues…." 10 CFR 51.53(c)(3)(iii)**
>
> **"…The environmental report must include an analysis that considers…the environmental effects of the proposed action…and alternatives available for reducing or avoiding adverse environmental effects.…" 10 CFR 51.45(c) as adopted by 10 CFR 51.53(c)(2) and 10 CFR 51.53(c)(3)(iii)**
>
> **The environmental report shall discuss "The impact of the proposed action on the environment. Impacts shall be discussed in proportion to their significance" 10 CFR 51.45(b)(1) as adopted by 10 CFR 51.53(c)(2)**
>
> **"…The information submitted…should not be confined to information supporting the proposed action but should also include adverse information." 10 CFR 51.45(e) as adopted by 10 CFR 51.53(c)(2)**

4.0 Introduction

Chapter 4 presents an assessment of the environmental consequences and potential mitigating actions associated with the renewal of the LSCS operating licenses.

In June 2013, the NRC published the final rule amending the environmental protection regulations for renewal of nuclear power plant operating licenses (NRC 2013a) and the GEIS, Revision 1 (NRC 2013b), that identified 78 issues to be evaluated in considering the impacts of license renewal.

Fifty-nine of the 78 issues are Category 1 issues.

Category 1 issues are those that meet all of the following criteria:

1. 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;
2. a single significance level (i.e., SMALL, MODERATE, or LARGE) has been assigned to the impacts (except for offsite radiological impacts—collective impacts from other than the disposal of spent fuel and high-level waste); and
3. mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that additional plant-specific mitigation measures are not likely to be sufficiently beneficial to warrant implementation.

Absent new and significant information (Chapter 5), NRC regulations do not require analyses of Category 1 issues because the NRC resolved them using generic findings presented in 10 CFR Part 51, Appendix B, Table B-1 (NRC 2013a). An applicant may reference the generic findings or GEIS analyses for Category 1 issues.

Category 2 issues are those that do not meet one or more of the criteria of Category 1, and therefore, require additional plant-specific review (NRC 2013b, pg S-6 & S-7). Seventeen of the 78 issues were determined to be Category 2, and 2 were left uncategorized. The NRC requires plant-specific analyses of Category 2 issues.

The NRC designated the two uncategorized issues (chronic effects of electromagnetic fields, and offsite radiological impacts of spent nuclear fuel and high-level waste disposal) as "uncertain", signifying that the categorization and impact definitions do not apply to these issues. Appendix A, Table A-1 of this Environmental Report lists the 78 issues and provides a summary of the applicability of each to LSCS. Appendix A, Table A-1 also identifies the section in this environmental report that addresses each issue and, where appropriate, references supporting analyses in the 2013 GEIS.

Category 1 License Renewal Issues

NRC

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

Exelon Generation determined that, of the 59 Category 1 issues identified in the GEIS, nine do not apply to LSCS because they apply to design or operational features that do not exist at the facility.

As discussed in Chapter 5, Exelon Generation performed a new and significant analysis of all Category 1 issues specific to LSCS and identified no new and significant information that would make the findings in the GEIS for any Category 1 issues inapplicable to LSCS. Section 4.13 presents the results of Exelon Generation's analysis of the partial rod fuel burn up rate of more than 62,000 MWD/MTU (see Section 2.2.2) which concludes that the higher burn up rate would not affect NRC's findings (NRC 2013a) regarding impacts of the fuel cycle as SMALL impacts. Thus, as noted in Section 5.2, the information is new but not significant.

Therefore, Exelon Generation adopts by reference the NRC findings for the 50 applicable Category 1 issues, and no further assessments of impacts associated with these Category 1 issues have been performed.

Category 2 License Renewal Issues

NRC

> **"The environmental report must contain analyses of the environmental impacts of the proposed action, including the impacts of refurbishment activities, if any, associated with license renewal and the impacts of operation during the renewal term, for those issues identified as Category 2 issues in Appendix B to subpart A of this part…." 10 CFR 51.53(c)(3)(ii)**
>
> **"The report must contain a consideration of alternatives for reducing adverse impacts, as required by § 51.45(c), for all Category 2 license renewal issues…." 10 CFR 51.53(c)(3)(iii)**

The NRC designated 17 issues as Category 2. Two Category 2 issues apply to operational features that LSCS does not have: Issue 22, groundwater use conflicts at plants that withdraw more than 100 gpm, and Issue 64, electric shock hazards at plants with in-scope offsite transmission lines.

Sections 4.1 through 4.15 in this environmental report address the 15 Category 2 issues identified in the 2013 GEIS that apply to LSCS and provide site-specific analyses of impacts. These analyses include conclusions regarding the significance of the impacts relative to the renewal of the operating licenses for LSCS and, when appropriate, discuss potential mitigation alternatives. Except in the cases of historic and cultural resources and federally-protected species, Exelon Generation has identified the significance of the impacts associated with each issue as SMALL, MODERATE, or LARGE, consistent with the following criteria that the NRC established in 10 CFR Part 51, Appendix B, Table B-1, Footnote 3:

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

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

Consistent with the NRC guidance provided in 10 CFR Part 51, Appendix B to Subpart A, Exelon Generation has adopted the impact determinations described below for historic and cultural resources, and for federally-protected species.

The National Historic Preservation Act requires the NRC to consider the effects on historic properties in the vicinity of the project site and provide a reasonable opportunity for the Advisory Council on Historic Preservation to comment. If continued operation, including refurbishment could result in adverse effects on a historic property, then the NRC must consult with the State Historic Preservation Officer (SHPO) to assess mitigation. Thus, regarding historic or cultural resources, the significance of effects from license renewal and the need for mitigation can be characterized based on a determination that (1) no historic properties are present (no effect); (2) historic properties are present, but not adversely affected (no adverse effect); or (3) historic properties are adversely affected (adverse effect) (NRC 2013a). Exelon Generation has used these determinations in its conclusion of license renewal impacts to historic and cultural resources.

In complying with the Endangered Species Act, NRC must consult with the U.S. Fish and Wildlife Service (USFWS) if the effects of authorizing continued nuclear power plant operations, including refurbishment, would adversely affect any protected species or critical habitat for a protected species. Thus, regarding species protected by the Endangered Species Act, the significance of the effects from license renewal and the need for NRC consultation with USFWS can be characterized based on a determination of whether continued nuclear power plant operations including refurbishment (1) would have no effect on federally-listed species, (2) are not likely to adversely affect federally-listed species, (3) are likely to adversely affect federally-listed species, or (4) are likely to jeopardize a federally-listed species or adversely modify designated critical habitat (NRC 2013a). Exelon Generation has used these determinations in its conclusion of license renewal impacts to species that are federally listed, candidates for listing, or proposed for listing as threatened or endangered species.

In complying with the Magnuson-Stevens Fishery Conservation and Management Act, NRC must consult with the National Marine Fisheries Service (NMFS) if the effects of authorizing continued nuclear power plant operations, including refurbishment, would adversely affect any essential fish habitat identified under the Act. Thus, regarding essential fish habitats, the significance of the effects from license renewal and the need for NRC consultation with NMFS can be characterized based on a determination of whether continued nuclear power plant operations, including refurbishment would have (1) no adverse impact, (2) minimal adverse impact, or (3) substantial adverse impact to the essential habitat of federally managed fish populations (NRC 2013a). Exelon Generation has used these determinations in its conclusion of license renewal impacts to essential habitats of federally managed fish populations.

"NA" License Renewal Issues

The NRC determined that its categorization and impact-finding definitions did not apply to two issues (Issues 62 [chronic effects of electromagnetic fields] and 70 [offsite radiological impacts of spent nuclear fuel and high-level waste disposal]); however, Exelon Generation includes both issues in Appendix A, Table A-1 in this environmental report.

Because NRC regulations do not require applicants to submit information on chronic effects from electromagnetic fields (10 CFR Part 51, Appendix B, Table B-1, Footnote 6) (NRC 2013a), Exelon Generation does not otherwise address issue 62.

4.1 Land Use and Visual Resources

The following Category 1 issues related to land use and visual resources were reviewed for new and significant information at LSCS that could make the generic finding for a resource as described in the 2013 GEIS inapplicable:

- Onsite land use
- Offsite land use
- Aesthetic impacts

No new and significant information was identified, therefore the conclusions regarding impacts to these resources in the 2013 GEIS are considered appropriate for the LSCS license renewal and impacts to land use and visual resources do not need further analysis. Section 3.2 describes land use and visual resources in the vicinity of LSCS.

Offsite land use in transmission line rights-of-way was not evaluated because, as is explained in Section 2.2.6, LSCS off-site transmission lines are not included in the scope of the LSCS license renewal environmental review.

4.2 Air Quality

Air quality resources are Category 1 issues and were reviewed for new and significant information at LSCS that could make the generic finding for a resource as described in the 2013 GEIS inapplicable.

No new and significant information was identified, therefore the conclusions regarding impacts to air quality in the 2013 GEIS are considered appropriate for the LSCS license renewal and do not need further analysis. Section 3.3 describes air quality is the region around LSCS.

Air quality effects of transmission lines were not evaluated because, as is explained in Section 2.2.6, no LSCS transmission lines are within the scope of the LSCS license renewal environmental review.

4.3 Noise

Noise impacts from the continued operation resulting from LSCS license renewal is a Category 1 issue that was reviewed for new and significant information at LSCS that could make the generic finding for a resource as described in the 2013 GEIS inapplicable, and no new and significant information was identified. Therefore, the conclusions regarding impacts from noise in the 2013 GEIS are considered appropriate for the LSCS license renewal and do not need further analysis. Section 3.4 describes noise from current plant operations.

4.4 Geology and Soils

Impacts from the continued operation resulting from license renewal to geology and soils are Category 1 issues that were reviewed for new and significant information at LSCS and no new and significant information was identified. Therefore, the conclusions regarding impacts to these resources in the 2013 GEIS are considered appropriate for the LSCS license renewal and no further analyses are needed. Section 3.5 discusses the geology and soils of the region and in the vicinity of LSCS.

4.5 Water Resources

4.5.1 Surface Water Use Conflicts (Plants with Cooling Ponds or Cooling Towers Using Makeup Water from a River)

NRC

> **"If the applicant's plant utilizes cooling towers or cooling ponds and withdraws makeup water from a river, an assessment of the impact of the proposed action on water availability and competing demands, and the flow of the river, … must be provided…" 10 CFR 51.53(c)(3)(ii)(A).**
>
> **"…Impacts could be of small or moderate significance, depending on makeup water requirements, water availability, and competing water demands…" 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 17**

Nuclear power plants with cooling ponds require makeup water to replace evaporative losses and, in some instances, seepage (to groundwater) losses. Although the rate of consumptive water use (chiefly evaporative losses) normally does not change over the operating life of a power plant, external circumstances and environmental conditions may change, increasing pressures on surface water supplies. For example, there may be an extended period of drought, a large population increase in the area, or an influx of industrial facilities (NRC 2013b). There could, in theory, be a change in precipitation patterns in the region. For this reason, NRC made surface water use conflicts a Category 2 issue requiring a site-specific analysis.

As discussed in Section 2.2.3, water is pumped from the Illinois River to LSCS's 833-ha (2,058-ac) cooling pond to replace blowdown, evaporative, and seepage losses. The Illinois River drains an approximately 21,391 km^2 (8,259 mi^2) drainage area upstream of Marseilles, Illinois (NRC 1978), which is 4 km (2.5 mi) downstream of LSCS's intake. The USGS maintains a permanent gaging station at Marseilles. For water years 1920-2012, annual mean flow at Marseilles ranged from 158,093 to 505,456 L/sec (5,583 to 17,850 cubic feet per second [cfs]) and averaged 304,689 L/sec (10,760 cfs) (USGS 2013b) or 5.7×10^9 ft^3/year.

Prior to 2006, there were no comprehensive statewide or regional plans for managing the water supply in Illinois. In January 2006, Executive Order (EO) 2006-01 was signed by the Governor of Illinois and called for a comprehensive program for state and regional water supply planning and management, a strategic plan for the program's implementation, and development of regional water supply plans in three priority planning regions: east central Illinois, northeastern Illinois, and the Kaskaskia area (ISWS 2012). LSCS is not within any of these priority planning regions.

One planning goal of EO 2006-1 is to manage rivers in Illinois to ensure that river flows remain above the interim 1-day, 10-year low ($Q_{1,10}$) or 7-day, 10-year low ($Q_{7,10}$) protected flow level. The $Q_{7,10}$ flow rate at Marseilles is estimated at 90,189 L/sec (3,185 cfs) (ISWS 1993) which is an order of magnitude greater than the total capacity of the plant's three makeup pumps (5,663 L/sec [200 cfs])[3]. Therefore, makeup water pumped to the cooling pond under normal

[3] Each pump has a design capacity of 114,000 L/min (30,000 gpm). Two pumps operate with one held in reserve. However, if all three pumps pumped at the same time, the maximum water removal from the Illinois River would be 5,663 L/sec (200 cfs) (Exelon Nuclear 2012a).

conditions is unlikely alone to cause the river flow rate in the Illinois River basin to fall below the rates that EO 2006-1 aims to protect. As discussed in Section 3.6.3.1, two other commercial/industrial water intakes withdraw from the Marseilles Pool of the Illinois River; Agrium U.S., Inc. and PCE Phosphate – Marseilles Operation. The volume of river water used by these facilities is unknown because water-use data for commercial/industrial facilities are protected as trade secrets, even from a Freedom of Information Act request. However, it is unlikely that current or future LSCS water withdrawals would contribute significantly to any combined adverse effects from the total commercial/industrial water withdrawals because LSCS withdrew only an average of 2,945 L/sec (104 cfs) for water years 2008 through 2012, or less than 1.0 percent of the Illinois River's 92-year annual average mean flow at the Marseilles Pool and no significant effects have been observed from this and all other current water uses in the Pool.

During drought conditions, the Illinois River flow rate could fall naturally below the rates that EO 2006-1 aims to protect. Should that occur, the river water surface elevation could drop to a level that would affect plant operations. Accordingly, as part of an overall Summer Readiness Plan, the LSCS Extreme Heat Implementation Plan provides specific guidance to plant personnel for responding to such circumstances during summer weather conditions. This plan recognizes that under worst-case summer weather conditions, Exelon Generation may operate the plant at less than its rated maximum power output or take other operational actions necessary to maintain compliance with the LSCS NPDES Permit requirements for thermal discharge to the river and to protect plant equipment.

In accordance with the LSCS Extreme Heat Implementation Plan, the plant's makeup water pumps would be shut down if the river water level falls to 146 m (478 ft) above msl. Also, if the river flow rate falls below the 1-day, 100-year low flow in Illinois River (45,080 L/sec [1,592 cfs]), then mass balance and heat reject calculations must be performed to determine if an NPDES thermal limit is being challenged. To maintain compliance, it may be necessary to adjust blowdown flow as well as makeup pumping rates, as determined on a case-specific basis.

The 2008 to 2012 average makeup withdrawal rate from the Illinois River was 2,945 L/sec (104 cfs), and an average of 1,586 L/sec (56 cfs) was returned to the river as blowdown for an average net consumptive use of 1,359 L/sec (48 cfs). The net consumptive water use from the river (approximately 1,359 L/sec [48 cfs]), was less than 0.5 percent of the river's 92-year annual average mean flow.

The plant's maximum makeup water withdrawal capacity is 5,663 L/sec (200 cfs, see footnote 1), which represents approximately 1.8 percent of the river's 92-year annual average mean flow. Assuming a maximum withdrawal of 5,663 L/sec (200 cfs) and using the plant's lowest average blowdown rate between 2008 and 2012 (878 L/sec [31 cfs] in 2008), the net consumptive water use from the river would be approximately 4,786 L/sec (169 cfs) which represents 1.5 percent of the river's 92-year annual average mean flow of 304,689 L/sec (10,760 cfs).

Evaluation of stream flow trends over a 90-year period for the upper Midwest shows a consistent trend of increasing stream flows. The increased flows are attributed to a 7- to 10-percent increase in precipitation over the past 30 years (Knapp Undated). The cause of the precipitation increase is not known but the plant's consumptive use during the license renewal term is not expected to increase beyond current rates. Hence, continued operation of the plant will not influence future Illinois River stream flow trends.

Based on the aforementioned findings, withdrawals of surface water for the operation of LSCS Units 1 and 2 would have a SMALL impact on the availability of water downstream of site and does not warrant further mitigation:

4.5.2 Groundwater Use

4.5.2.1 Groundwater Use Conflicts (Plants That Withdraw > 100 gpm)

NRC

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

"…Plants that withdraw more than 100 gpm could cause groundwater use conflicts with nearby groundwater users …." 10 CFR 51, Subpart A, Table B-1, Issue 22

NRC made groundwater use conflicts a Category 2 issue because, at a withdrawal rate of more than 100 gallons per minute (gpm), a cone of depression could extend offsite. This could deplete the groundwater supply available to offsite users, an impact that could warrant mitigation.

The issue of groundwater use conflicts does not apply to LSCS because the plant does not use more than 6.3 L/sec (100 gpm) of groundwater from the two onsite wells, Well #1 and Well #2. As discussed in Section 3.6.4.2, between the years 2008 and 2012, Well #1 pumped an average 1.3 L/sec (20.8 gpm), and Well #2 pumped an average 0.33 L/sec (5.3 gpm) for a total groundwater withdrawal rate of 1.6 L/sec (26.1 gpm). Although these are recent pump data, they are typical of annual average pump rates for the current license period. Because LSCS has no plans to change operational procedures or processes during the renewal term, the annual average pump rates will not exceed 6 L/sec (100 gpm).

4.5.2.2 Groundwater Use Conflicts (Plants with Closed-Cycle Cooling Systems That Withdraw Makeup Water from a River)

NRC

"If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river …[t]he applicant shall…provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow." 10 CFR 51.53(3)(ii)(a)

"…Water use conflicts could result from water withdrawals from rivers during low-flow conditions, which may affect aquifer recharge. The significance of impacts would depend on makeup water requirements, water availability, and competing water demands. …" 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 23

The NRC made groundwater use conflicts a Category 2 issue because consumptive use of river water could adversely affect aquifer recharge. This is a particular concern during low flow conditions and could result in a more severe cumulative impact to the aquifer recharge system if the river supported several to many consumptive users. LSCS uses a cooling pond, which loses water through blowdown, evaporation and seepage. This lost water is made up with water pumped from the Illinois River.

The USGS maintains a permanent gaging station at Marseilles. For water years 1920-2012, annual mean flow at Marseilles ranged from 158,093 to 505,456 L/sec (5,583 to 17,850 cfs) and averaged 304,689 L/sec (10,760 cfs) (USGS 2013b) or 5.7×10^9 ft^3/year.

The Marseilles Pool of the Illinois River is not used for public water supply. As discussed in Section 3.6.4.1, groundwater for public use within 16 km (10 mi) of the site comes predominantly from wells installed in the Cambrian-Ordovician Aquifer. Water supplies for Seneca, Kinsman, Marseilles, and the Illini State Park are taken entirely from this aquifer. Ransom withdraws groundwater from both the Cambrian-Ordovician Aquifer and permeable zones in the Pennsylvanian Aquitard. Grand Ridge is the only municipality within 16 km (10 mi) that gets water from the glaciofluvial deposits of the Buried Bedrock Valley Aquifer. The rest of the small communities within 16 km (10 mi) of the site are not served by public water supplies. Residents in these communities and the surrounding rural areas pump groundwater from individual wells in the glacial drift, the Pennsylvanian strata, or the upper portion of the Cambrian-Ordovician Aquifer.

As discussed in Section 3.6.2, the closest alluvial aquifer to the site is adjacent to the Illinois River. Although alluvial deposits are present on both sides of the river valley, the river functions as a hydrogeologic discharge boundary, thereby separating the alluvial aquifers on either side of the river from each other. The alluvial aquifer on the south side of the river extends along the river and is bounded on the north by the river and on the south by the valley walls. The width of the aquifer ranges from 183 m (600 ft) to 2,134 m (7,000 ft). The width of the aquifer in the vicinity of the river screen house ranges from 1,067 to 1,463 m (3,500 to 4,800 ft). Groundwater elevations in the alluvial aquifer decrease from the valley walls toward the river, indicating that groundwater flows toward the river, with localized flow toward South Kickapoo Creek (Exelon Nuclear 2012a).

The aquifer occurs under water table conditions and receives recharge primarily by precipitation and inflow from the river during periods of high river levels. Yields from the alluvial aquifer in the vicinity of the site are not known, but are most likely adequate for domestic use only (Exelon Nuclear 2012a). The alluvial aquifer is separated from the primary drinking water aquifer (Cambrian-Ordovician Aquifer) by the Pennsylvanian Aquitard (Figure 3.5-1), which is approximately 53.6 m (176 ft) thick and consists of relatively impermeable shale and siltstone.

As discussed in Section 3.6.4.2, LSCS uses two water sources: the Illinois River for condenser cooling and groundwater for all other uses. Two deep wells (Well #1 and Well #2) at LSCS withdraw groundwater from the Cambrian-Ordovician Ironton-Galesville Sandstone Aquifer. LSCS uses groundwater from the two wells for potable and demineralizer system water. As summarized in Table 3.6-4, between the years 2008 and 2012, Well #1 pumped an average 1.3 L/sec (20.8 gpm), and Well #2 pumped an average 0.33 L/sec (5.3 gpm) for a total groundwater withdrawal rate of 1.6 L/sec (26.1 gpm).

As discussed in Section 2.2.3, makeup water is pumped from the Illinois River to the cooling reservoir to replace losses due to evaporation, blowdown, and seepage. The makeup pumps have a total capacity of 5,663 L/sec (200 cfs). The rate of pumping varies depending on the plant operating load level and weather conditions, but would only be at the maximum capacity during an emergency. Although the design maximum blowdown rate (see Section 2.2.3) is approximately 340,000 L/min (90,000 gpm), valve settings limit normal blowdown flow to 220,000 L/min (58,000 gpm) or less with a target annual average of 114,000 L/min (30,000 gpm). The actual average blowdown rate for 2008 through 2012 was 1,586 L/sec (56 cfs; 25,269 gpm). During drought conditions, the LSCS Extreme Heat Implementation Plan provides specific guidance to plant personnel for responding under worst-case summer weather conditions, which may cause Exelon Generation to operate the plant at less than maximum load or take other operational actions, such as adjusting blowdown flow and makeup pumping rates, to ensure compliance with the LSCS NPDES Permit requirements for thermal discharge to the river and to protect plant equipment. Hence, the LSCS Extreme Heat Implementation Plan would mitigate most potential impacts from makeup water withdrawals during drought conditions.

The 2008 to 2012 average makeup withdrawal rate from the Illinois River was 2,945 L/sec (104 cfs), and an average of 1,586 L/sec (56 cfs) was returned to the river as blowdown for an average net consumptive use of 1,359 L/sec (48 cfs). The Illinois River's 92-year annual average mean flow is 304,700 L/sec (10,760 cfs) (USGS 2013b). The plant's average (net) water use (average makeup water volume withdrawn minus volume returned to river as blowdown is 1,359 L/sec (48 cfs; 104 cfs - 56 cfs = 48 cfs) at 100 percent load, which represents less than 0.5 percent of the river's 92-year annual average mean flow.

In Illinois, there is no general permitting system for surface water withdrawals. Illinois follows the Riparian Doctrine of Reasonable Use: Each person owning land next to a stream is entitled to the reasonable use of the stream's water provided that such use doesn't interfere with the reasonable use by others with riparian rights (IDOT 1985).

Based on the aforementioned findings, withdrawals of surface water from the Illinois River for the operation of LSCS would have a SMALL impact on the availability of water in the alluvial aquifer and would not warrant further mitigation.

Additionally, groundwater use by LSCS has no effect on the alluvial aquifer and therefore no impact to Illinois River water levels or stream flow. The plant pumps less than 100 gpm from the Cambrian-Ordovician Aquifer which has no hydraulic contact with the much shallower alluvial aquifer.

4.5.2.3 Groundwater Quality Degradation (Plants with Cooling Ponds at Inland Sites)

NRC

> **"If the applicant's plant is located at an inland site and utilizes cooling ponds, an assessment of the impact of the proposed action on groundwater quality must be provided." 10 CFR 51.53(c)(3)(ii)(D)**
>
> **" Inland sites with closed-cycle cooling ponds could degrade ground-water quality. The significance of the impact would depend on cooling water pond quality, site hydrogeologic conditions (including the interaction of surface water and groundwater), and the location, depth, and pump rate of water wells." 10 CFR 51, Subpart A, Appendix B, Table B 1, Issue 26.**

NRC made degradation of groundwater quality a Category 2 issue because evaporation from closed-cycle cooling ponds concentrates dissolved solids in the water and settles suspended solids. In turn, seepage into the water table aquifer from the cooling pond could degrade groundwater quality. The issue of groundwater degradation applies to LSCS because the plant is located at an inland site and uses a cooling pond. As Section 2.2.3 describes, the LSCS circulating water systems withdraw from and discharge to an 833 ha (2,058-ac) cooling pond.

Groundwater quality in Illinois is protected by the regulations set forth in the 1987 Illinois Groundwater Protection Act (IGPA) (415 ILCS 33/1). The Illinois EPA has a groundwater quality protection program designed to restore, protect, and enhance the state's groundwater as a natural resource.

The cooling pond is enclosed on the north, east, and south by 11,565 m (37,942 ft) of dikes. The natural topography serves as the shoreline on the west side of the cooling pond. Three baffle dikes (Exelon Nuclear 2012a) within the cooling pond slow the water flow to prolong cooling time, ensuring that the coolest water is available at the lake screen house.

At normal pool, the cooling pond has a capacity of 3,911 ha-meters (31,706 ac-ft). Makeup water for the cooling pond is piped approximately 5.6 km (3.5 mi). (Exelon Nuclear 2012a).

Cooling water quality in the cooling pond is maintained by selective blowdown to the river, control of plant discharges into the cooling pond per the site's NPDES permit, and application of water treatment additives that are utilized for scale inhibition, silt dispersion, corrosion inhibition, and micro- and macro-biological control (Exelon Generation 2011c). In accordance with the plant's NPDES permit, cooling water quality at the discharge to the Illinois River must meet the following chemical parameters: pH between 6 and 9, and maximum total residual chlorine concentration of 0.05 milligrams per liter (mg/L) or less (IEPA 2013).

The total dissolved solids concentration in the cooling pond are limited by LSCS procedures to a maximum of 750 mg/L, which is less than half the total dissolved solids concentration of the underlying drinking water aquifer (1,709 mg/L) in the Cambrian-Ordovician Aquifer (Exelon Nuclear 2012a).

Tritium concentrations in the cooling pond do not exceed 200 pCi/L (Exelon Generation 2013c).

Seepage from the cooling pond is negligible because the pond was excavated almost entirely in Wedron silty clay till. The two-dimensional computer model SEEPAGE estimated the rate of seepage through the peripheral dike and subsoil beneath the dike. The permeability of the materials was determined from tests performed on undisturbed and remolded samples of Wedron silty clay till from test borings and pits in the reservoir area. The model indicated that the rate of seepage through the dike base would total 3.8 L (1 gal) per day or $1.5x10^{-6}$ cfs per foot of dike (Exelon Nuclear 2012a). Hence, the quantity of seepage through the cooling pond bottom would be negligible because of the thickness (36.6 to 42.7 m [120 to 140 ft]; see Section 3.5) and the impermeability of the Wedron silty clay till underlying it.

The aquifers beneath the cooling pond and Wedron strata include the Buried Bedrock Valley Aquifer; thin discontinuous aquifers in the Pennsylvanian Aquitard; and the Cambrian-Ordovician Aquifer (see Figure 3.5-1 and Table 3.5-1). The following paragraphs summarize the water quality in these deep aquifers.

Groundwater in the Buried Bedrock Valley Aquifer is moderately soft to hard (hardness ranges from 77 to 175 mg/L). Alkalinity ranges from 276 to 356 mg/L, total dissolved solids from 285 to 376 mg/L, chloride from 0.3 to 8 mg/L, and nitrate from 0.1 to 6 mg/L (Exelon Nuclear 2012a).

The Pennsylvanian strata are generally unfavorable as aquifers but groundwater quality in the upper 30.5 m to 61 m (100 to 200 ft) of the strata is acceptable for most domestic and farm purposes (Exelon Nuclear 2012a).

As discussed in Section 3.6.2, the Cambrian-Ordovician Aquifer is the primary source of groundwater, including drinking water, in the area, and the aquifer from which LSCS pumps its groundwater. The quality of groundwater in the Cambrian-Ordovician Aquifer is not homogeneous; therefore, the water quality can be determined only for the aquifer as a whole. The mean concentrations of the following parameters in the aquifer are: chloride 659 mg/L, sulfate 168 mg/L, alkalinity 274 mg/L, hardness 636 mg/L, and total dissolved solids 1,709 mg/L (Exelon Nuclear 2012a). As discussed in Section 3.6.2, the cooling pond is separated from the Cambrian-Ordovician Aquifer by more than 100 m (330 ft) of predominantly clay sediments, which effectively seal this deep aquifer from any cooling pond seepage.

The continued use of the LSCS cooling pond during the license renewal term would not affect groundwater because seepage from the cooling pond is negligible due to the thickness and impermeability of the Wedron silty clay till underlying it, and the cooling pond is separated from the Cambrian-Ordovician Aquifer, which is the primary source of groundwater, by more than 100 m (330 ft) of predominantly clay sediments, which protects the deep (drinking water) aquifer from any cooling pond seepage.

In addition, LSCS has (1) a Radiological Groundwater Protection Program (see Section 3.6.6.2) with procedures to monitor shallow groundwater and ensure the remediation of radiological spills to groundwater or soils, (2) a Spill Prevention Control and Countermeasures Plan (see Section 3.6.7) and procedures to minimize oil spills and any adverse environmental effect, (3) a Hazardous Materials Preincident Plan and an Incidental Chemical Spill Response procedure to minimize spills of chemicals and any adverse environmental effect, and (4) a Storm Water Pollution Prevention Plan. Thus, license renewal would have a SMALL impact on groundwater quality that would not warrant mitigation.

4.5.2.4 Radionuclides Released to Groundwater

NRC

"An applicant shall assess the impact of any documented inadvertent releases of radionuclides into groundwater. The applicant shall include in its assessment a description of any groundwater protection program for the site, including a description of any monitoring wells, leak detection equipment, and procedures for the surveillance of piping and components containing radioactive liquids for which a pathway to groundwater may exist. The assessment must also include a description of any past inadvertent releases… and the projected impact to the environment during the license renewal term, including the projected transport pathways, potential receptors (e.g., aquifers, rivers, lakes, ponds, ocean) and the projected concentrations of the radionuclides." 10 CFR 51.53(c)(3)(ii)(P).

"…Leaks of radioactive liquids from plant components and pipes have occurred at numerous plants. Groundwater protection programs have been established at all operating nuclear power plants to minimize the potential impact from any inadvertent releases. The magnitude of impacts would depend on site-specific characteristics.…" 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 27

The NRC made the release of radionuclides to groundwater a Category 2 issue because inadvertent releases to groundwater of liquids containing radioactive materials have occurred at some nuclear power plants.

Since 1982, Exelon Generation's Radiological Environmental Monitoring Program has monitored tritium and gamma-emitting radionuclide concentrations in the Cambrian-Ordovician Aquifer System at four water supply wells near LaSalle: LSCS production Well #1 and the City of Marseilles Wells 4, 5 and 6. No tritium or other radionuclide concentrations above their lower limits of detection (LLDs) were found in the wells during 2012 (Exelon Generation 2013c), consistent with previous years.

4.5.2.4.1 Radionuclides from Past Releases

Historic inadvertent radionuclide releases discussed in Sections 3.6.6.2 and 3.6.7, are summarized below:

- *1985 HPCS Cycled Condensate Line Break*. A review of the groundwater sampling data associated with this release and data from the more recent hydrologic investigation indicates decreasing tritium concentrations from a high of 11,000 pCi/L in 1986 to non-detectable at the LLD (200 pCi/L) in 2012.
- *2001 U2 Recycled Condensate Storage (CY) Tank Overflow.* The spill was evaluated for several isotopes, however not for tritium. In 2006 tritium concentrations were detected in monitoring well MW-LS-105S at concentrations from 1,280 ± 184 pCi/L to 766 ± 153 pCi/L. The source of this tritium is most likely the release described above for the U2 CY storage tank overflow (CRA 2006).

- *2006 Blowdown Line Investigation*. In 2006, 16 of 17 water samples collected from vacuum breakers located along the blowdown line had no detectable tritium concentrations. One sample had a tritium concentration of 274 ± 129 pCi/L. The sample was re-analyzed using the distillation process, resulting in a revised tritium concentration of less than the LLD of 200 pCi/L.
- *2010 U1 Cycled Condensate (CY) Tank Leak*. In 2010, a leak from the U1 Recycled Condensate tank was identified and remediated. Because the resultant tritium plume was dispersing with groundwater flow, an extraction well was installed to control the migration of the plume. To date, no tritium has migrated offsite, and tritium migration offsite is not expected.

Information on naturally-occurring radioactive isotopes is presented in Section 3.6.6.1. As a result of spills, radionuclides are present in groundwater in the upper portions of the Wedron silty clay till beneath the site. Radionuclide concentrations measured during the most recently available sampling year (2012) are shown on Figure 4.5-1 and summarized in Table 4.5-3.

As discussed in Section 3.6.6.2, Exelon Generation conducted a hydrogeologic investigation at the site in 2006 (CRA 2006). As part of the hydrogeologic investigation, 13 new monitoring wells (MW-LS-101S through MW-LS-113S) were installed (Figure 4.5-1) and sampled for tritium, strontium-89/-90, and gamma-emitting radionuclides. The results of the hydrogeologic investigation determined that gamma-emitting radionuclides and strontium-89/-90 did not occur at concentrations greater than their respective LLDs in any of the groundwater samples analyzed. Tritium was not detected at concentrations greater than the EPA's drinking water standard of 20,000 pCi/L although tritium was detected in one well, MW-LS-105S, at a concentration of 1,280 ± 184 pCi/L, which exceeds the LLD of 200 pCi/L. Samples from

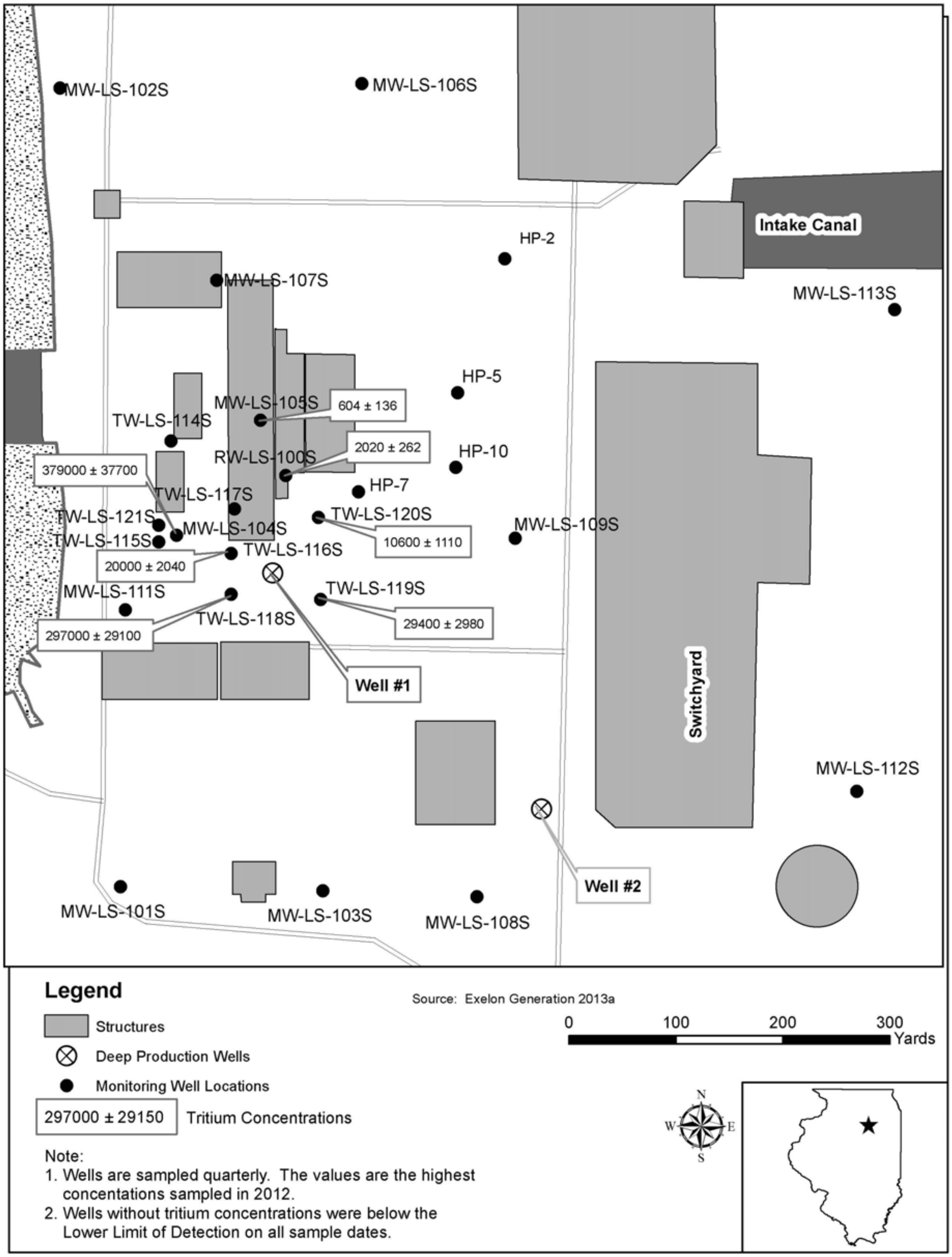

Figure 4.5-1 Tritium Concentrations in Groundwater Monitoring Wells

adjacent monitoring wells had no detectable tritium concentrations. The source of tritium in MW-LS-105S during 2006 was believed to be from a 2001 recycled condensate tank release (Exelon Generation 2013c).

4.5.2.4.2 Radiological Groundwater Protection Program (RGPP)

As described in Section 3.6.6.2, Exelon Generation established a site-specific Radiological Groundwater Protection Program (RGPP) sampling program at LSCS in 2006. Table 4.5-1 lists the available LSCS RGPP wells and describes the known characteristics of each well. Groundwater elevations beneath the plant are provided in Table 4.5-2.

MW-LS-104S, MW-LS-105S, MW-LS-106S, MW-LS-107S, and MW-LS-111S, which were originally installed as part of the 2006 hydrogeologic investigation, were incorporated into the RGPP and were monitored during 2012.

The 2012 RGPP sampling results are listed in Table 4.5-3 for tritium, strontium-89/-90, and all gamma-emitting radionuclides attributable to plant operations. Strontium-89/-90 were not detected in any groundwater samples during 2012.

Tritium was detected at concentrations greater than the LLD of 200 pCi/L at 7 of the 18 RGPP groundwater monitoring locations sampled during 2012 (Table 4.5-3 and Figure 4.5-1). For tritium, Exelon Generation requires its laboratory to achieve a lower limit of detection of 200 pCi/L, which is 100 times lower than the EPA's maximum concentration allowed in drinking water (Exelon Generation 2013c).

During 2012, tritium was detected in MW-LS-105S at concentrations from less than the LLD to 604 ± 136 pCi/L and in nearby MW-LS-104S at concentrations from 245,000 ± 24,400 pCi/L to 379,000 ± 37,700 pCi/L, and in all TW-LS wells in concentrations from less than the LLD to 297,000 pCi/L (Exelon Generation 2013c). These elevated concentrations are associated with the 2010 leak from the Unit 1 recycled condensate tank as documented in the Station's 10CFR50.75(g) report (Exelon Generation 2013c) and described in Section 3.6.6.2.

Based on results of the 2012 RGPP monitoring, Exelon Generation concludes that the occurrence of radionuclides in the groundwater beneath LSCS is not adversely affecting offsite groundwater. Onsite impacts from the 2010 leak in the Unit 1 recycled condensate tank, are small because the low permeability of till and shale layers under the site will slow vertical migration time to the underlying aquifer (Exelon 2011b), and the plume is being remediated via well RW-LS-100S. Remedial progress is monitored via monitoring wells MW-LS-105S and MW-LS-104S and the TW-LS well series (Exelon Generation 2013c).

4.5.2.4.3 Groundwater Flow

Groundwater flow in the Wedron silty clay till is discussed in detail in Section 3.6.2 and illustrated in Figure 3.6-2. Groundwater flow in the deep Cambrian-Ordovician Aquifer beneath the site is to the northeast.

As discussed in Section 3.6, the movement of water from the Wedron silty clay till to aquifers beneath the site is negligible because of the thickness (37 to 43 m [120 to 140 ft]) and the impermeability of the till. The areas of historic radionuclide releases are vertically separated from the underlying Cambrian-Ordovician Aquifer by more than 100 m (330 ft) of predominantly clay sediments, which effectively seal the deep aquifer from any radionuclides inadvertently released to the shallow groundwater.

4.5.2.4.4 Conclusion

The continued operation of LSCS would not increase the concentrations of radionuclides in the Cambrian-Ordovician Aquifer System because (1) seepage from surface releases to the Cambrian-Ordovician Aquifer System would not occur due to the thickness and impermeability of the Wedron silty clay till underlying the site, and the depth of the Cambrian-Ordovician Aquifer System, (2) the shallow aquifer which is contaminated with tritium under the site is not used for drinking water, and no tritium has migrated offsite, and (3) LSCS has a groundwater protection sampling program that monitors groundwater and provides for remediation of radioactive spills to groundwater or soils. Thus, renewal of the LSCS operating licenses would have a SMALL impact on groundwater contamination and would not warrant mitigation.

Table 4.5-1 Summary of Onsite Well Installation Details (Production and Monitoring Wells)

Well ID	Install Date[1]	Boring Total Depth (ft bgs) [2]	Screened Interval [m(ft) bgs [2]	Well Construction[2]	Media Screened[2]
Site Production Well # 1	1974	496.5 (1,629)[3]	N/A	12-20 inch pipe	Drift, clay, shale, limestone, sandstone
Site Production Well # 2	1972	494 (1,620)[3]	N/A	N/A	N/A
MW-LS-101S	2006	4.6 (15)	1.5 to 4.6 (5 to 15)	2-in PVC	Silty clay
MW-LS-102S	2006	9.1 (30)	3 to 6.1 (10 to 20)	2-in PVC	Clay
MW-LS-103S	2006	4.9 (16)	1.5 to 4.6 (5 to 15)	2-in PVC	Silty Clay
MW-LS-104S	2006	4.6 (15)	0.9 to 4.0 (3 to 13)	2-in PVC	Sand, gravel, silty clay
MW-LS-105S	2006	4.6 (15)	0.9 to 4.0 (3 to 13)	2-in PVC	Sand, gravel, silty clay
MW-LS-106S	2006	4.6 (15)	0.61 to 3.7 (2 to 12)	2-in PVC	Gravel, sand, clay
MW-LS-107S	2006	4.6 (15)	1.2 to 4.3 (4 to 14)	2-in PVC	Gravel, sand, cobbles, clay
MW-LS-108S	2006	4.6 (15)	0.9 to 4.0 (3 to 13)	2-in PVC	Silty clay
MW-LS-109S	2006	4.6 (15)	0.9 to 4.0 (3 to 13)	2-in PVC	Sand, gravel, silty clay
MW-LS-110S[4]	2006	2 (6.5)	0.46 to 2.0(1.5 to 6.5)	2-in PVC	Silty clay
MW-LS-111S	2006	4.3 (14)	1.2 to 4.3 (4 to 14)	2-in PVC	Clay
MW-LS-112S	2006	4.6 (15)	1.2 to 4.3 (4 to 14)	2-in PVC	Silty clay
MW-LS-113S	2006	4.6 (15)	1.2 to 4.3 (4 to 14)	2-in PVC	[2]
HP-2	1985	7.6 (25)[5]	N/A	N/A	N/A
HP-5	1985	10.4 (34)[5]	N/A	N/A	N/A
HP-7	1985	8.8 (29)[5]	N/A	N/A	N/A
HP-10	1985	3.35 (11)[5]	N/A	N/A	N/A
RW-LS-100S	2012	4.3 (14)	1.2 to 4.3 (4 to 14)	2-in PVC	N/A
TW-LS-114S	2010	4.6 (15)	1.5 to 4.6 (5 to 15)	2-in PVC	Sand, gravel, silty clay
TW-LS-115S	2010	4.6 (15)	1.5 to 4.6 (5 to 15)	2-in PVC	Clay
TW-LS-116S	2010	4.6 (15)	1.5 to 4.6 (5 to 15)	2-in PVC	Clay
TW-LS-117S	2010	4.6 (15)	1.5 to 4.6 (5 to 15)	2-in PVC	Clay

Table 4.5-1 Summary of Onsite Well Installation Details (Production and Monitoring Wells) (Continued)

Well ID	Install Date	Depth[m (ft)][2]	Screened Interval (ft bgs)	Well Construction	Media Screened
TW-LS-118S	2010	4.6 (15)	1.5 to 4.6 (5 to 15)	2-in PVC	Clay
TW-LS-119S	2010	4.6 (15)	1.5 to 4.6 (5 to 15)	2-in PVC	Sand, gravel, silty clay
TW-LS-120S	2012	3 (10)	1.5 to 3 (5 to 10)	2-in PVC	Sand, gravel
TW-LS-121S	2012	3 (10)	1.5 to 3 (5 to 10)	2-in PVC	Sand, gravel

Sources: CRA 2006; Exelon Undated; Exelon Generation 2013c; ISGS Undated
N/A = not available

[1] Wells installed in 1985 were installed to monitor tritium from the High Pressure Condensate Spray line break in 1986 and 1987. Wells installed in 2006 were part of the initial hydrogeologic investigation (CRA 2006). Later wells were added as needed to monitor releases and resulting plumes.
[2] CRA-2006
[3] Exelon Generation 2012a
[4] Well MW-LS-100S is located adjacent to Valve Pit No. 16B, which is just upstream of the blowdown flow control valve at the discharge point on the Illinois River (CRA 2006)
[5] Exelon Undated. RGPP Reference Material for LaSalle Generating Station. EN-LA-408-4160, Revision 3.

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Table 4.5-2 Summary of Site Ground Water Levels

Well ID	Measurement Date	Depth to Ground Water (ft bgs)	Ground Water Elevation (ft msl)
Well # 1	Jan 1974	260	451
Well # 2	N/A	N/A	N/A
MW-LS-101S	July 2006	4.92	700.60
MW-LS-102S	July 2006	17.16	689.90
MW-LS-103S	July 2006	6.21	702.70
MW-LS-104S	July 2006	8.01	704.15
MW-LS-105S	July 2006	8.27	704.14
MW-LS-106S	July 2006	5.91	705.50
MW-LS-107S	July 2006	3.97	704.75
MW-LS-108S	July 2006	6.66	707.36
MW-LS-109S	July 2006	2.37	708.90
MW-LS-110S	July 2006	9.51	496.34
MW-LS-111S	July 2006	4.24	701.17
MW-LS-112S	July 2006	8.58	710.09
MW-LS-113S	July 2006	13.40	710.81
HP-2	1985	5.59	707.55
HP-5	1985	5.94	705.20
HP-7	1985	7.12	704.35
HP-10	1985	3.60	705.01
RW-LS-100S	N/A	N/A	N/A
TW-LS-114S	N/A	N/A	N/A
TW-LS-115S	N/A	N/A	N/A
TW-LS-116S	N/A	N/A	N/A
TW-LS-117S	N/A	N/A	N/A
TW-LS-118S	N/A	N/A	N/A
TW-LS-119S	N/A	N/A	N/A
TW-LS-120S	N/A	N/A	N/A
TW-LS-121S	N/A	N/A	N/A

Sources: CRA 2006; ISGS Undated
N/A = not available

Table 4.5-3 Highest Concentrations of Sampled Radionuclides in Site Groundwater in 2012 (pCi/L)

Well ID	Designation[1]	Sample Year[2]	Tritium	Sr-89	Sr-90	Gross Alpha (Dissolved)	Gross Alpha (Suspended)	Gross Beta (Dissolved)	Gross Beta (Suspended)
MW-LS-101S	I		-	-	-	-	-	-	-
MW-LS-102S	I		-	-	-	-	-	-	-
MW-LS-103S	I		-	-	-	-	-	-	-
MW-LS-104S	E	2012	379,000 ± 37,700	<3.1	<0.6	<0.6	<1.6	<3.1	4.3 ± 0.7
MW-LS-105S	D	2012	604 ± 136	<3.2	<0.6	<0.8	<1.2	3.6 ± 0.9	17.9 ± 1.2
MW-LS-106S	B	2012	<190	-	-	<1.5	3.7 ± 1.7	2.5 ± 1.1	16.4 ± 2.5
MW-LS-107S	D	2012	<198	<1.8	<0.6	<1.6	<1.2	3.0 ± 1.2	3.7 ± 0.9
MW-LS-108S	I		-	-	-	-	-	-	-
MW-LS-109S	I		-	-	-	-	-	-	-
MW-LS-110S	I		-	-	-	-	-	-	-
MW-LS-111S	D	2012	<195	<2.0	<0.6	<4.2	<1.9	14.5 ± 3.9	7.1 ± 2.0
MW-LS-112S	I		-	-	-	-	-	-	-
MW-LS-113S	I		-	-	-	-	-	-	-
HP-2	D	2012	<197	<2.8	<0.5	<2.3	<5.7	25.1 ± 3.8	13.0 ± 2.2
HP-5	D	2012	<198	<3.1	<0.6	2.0 ± 1.2	7.1 ± 0.8	4.3 ± 1.2	4.2 ± 0.6
HP-7	D	2012	<199	<2.8	<0.6	<4.1	<1.1	12.3 ± 2.1	<2.0
HP-10	D	2012	<197	<3.3	<0.6	<4.9	<1.1	<5.9	<2.6
RW-LS-100S	recovery well	2012	2020 ± 262	<5.5	<0.7	<0.6	<0.3	3.8 ± 0.9	<1.7
TW-LS-114S	P	2012	<195	-	-	-	-	-	-
TW-LS-115S	P	2012	<190	-	-	-	-	-	-
TW-LS-116S	P	2012	20,000 ± 2040	-	-	-	-	-	-

Table 4.5-3 Highest Concentrations of Sampled Radionuclides in Site Groundwater in 2012 (pCi/L) (continued)

Well ID	Designation[1]	Sample Year[2]	Tritium	Sr-89	Sr-90	Gross Alpha (Dissolved)	Gross Alpha (Suspended)	Gross Beta (Dissolved)	Gross Beta (Suspended)
TW-LS-117S	P	2012	<174	-	-	-	-	-	-
TW-LS-118S	P	2012	297,000 ± 29,100	-	-	-	-	-	-
TW-LS-119S	P	2012	29,400 ± 2980	-	-	-	-	-	-
TW-LS-120S	P	2012	10,600 ± 1110	-	-	-	-	-	-
TW-LS-121S	P	2012	<186	-	-	-	-	-	-

Sources: Exelon Generation 2013c; CRA 2006; Exelon Generation 2011b.
"-" = Parameter not analyzed
[1] Designation: B = background; D = detection wells installed close to higher risk systems or components where leak detection capabilities are recommended; E = monitor detectable concentrations present from previous leaks or spills that are no longer covered by an Adverse Condition Monitoring and Contingency Plan; I = currently not being sampled but available for future use; L = in place to monitor the decommissioning process; P = monitor concentrations of licensed materials in plumes with fairly predictable results.
[2] Wells are sampled quarterly. The values in this table are the highest concentration measured at each well in 2012.

4.6 Ecological Resources

4.6.1 General Approach for Information and Analysis Content for All Ecological Issues

4.6.1.1 Aquatic Resources

Exelon Generation used reports and summaries published by the Illinois Natural History Survey (INHS) to provide a historical perspective and as a source to describe changes in the Illinois River since the 1950s. The INHS began systematically monitoring fish populations of the entire Illinois River in 1957, with the goal of detecting possible anthropogenic changes, and continues to do so today. Lerczak summarized the first 37 years of the INHS's Illinois River fish monitoring in a 1994 project completion report (Lerczak, et. al 1994) and a 1996 article (Lerczak 1996) offered commentary on how the increase in abundance of desirable species reflected improved water quality in the basin.

To characterize the aquatic communities of the Marseilles Pool, from which LSCS withdraws cooling pond makeup water, and to which it discharges cooling pond blowdown, Exelon Generation reviewed results of monitoring studies described in the Environmental Report - Operating Stage (ComEd 1977) and summarized in the NRC's FES for operation (NRC 1978). These included baseline (pre-construction) monitoring of plankton, benthos, and fish in 1972-1973 and construction-phase monitoring of these same groups in 1974, 1975, and 1976. These baseline and construction-phase monitoring studies extended from RM 249.7, upstream of the intake location, to RM 248.7, downstream of the discharge (blowdown) location. This reach of the river encompassed the mouth of South Kickapoo Creek, which was also surveyed.

To update this information and attempt to identify changes in fish populations following construction and operation of LSCS, Exelon Generation sought the assistance of the INHS's Illinois River Biological Station, in Havana, Illinois. The Station staff provided 20 years (1993-2012) of electrofishing data for three monitoring stations in the Marseilles Pool, two upstream (Waupecan Island, Johnson Island) and one downstream (Ballards Island) of the LSCS discharge/blowdown. Examining "normalized" trends in electrofishing catches (catch per unit of effort) at these stations made it possible for Exelon Generation to make conclusions relative to the status of important fish populations and draw inferences about potential intake and discharge impacts.

As Section 2.2.3 indicates, the LSCS cooling pond is a wastewater treatment works (35 IAC 301.415), and as such it is excepted from the definition of "waters of the state" (35 IAC 301.440) as well as the definition of "waters of the United States" under the federal Clean Water Act (40 CFR 230.3(s)). As a result, assessment of aquatic resources in the cooling pond is not required, and no studies of such effects have been performed.

4.6.1.2 Terrestrial Resources

For this environmental report, Exelon Generation used the Environmental Report, Operating License Stage (ComEd 1977) to characterize the terrestrial communities of the LSCS property in the 1970s, before the plant was built. Plant and animal inventories conducted in 2007 in support of the LaSalle County Generating Station Wildlife Management Plan (Exelon Generation 2013b) provided updated information on these communities and on initiatives Exelon Generation has undertaken to restore and enhance native tallgrass prairie on the site and habitat for grassland birds. For threatened and endangered species, Exelon Generation relied on the websites of Illinois DNR and the U.S. Fish and Wildlife Service, Midwest Region, and in particular the two agencies' county lists of special-status species. The impact assessment was largely a matter of determining, through interviews with Exelon staff at the plant and corporate headquarters, if any construction projects or changes in plant operations were anticipated.

No further monitoring and no additional studies were conducted.

4.6.2 Terrestrial Resources

4.6.2.1 Effects on Terrestrial Resources (Non-Cooling System Impacts)

NRC

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

"Impacts resulting from continued operations and refurbishment associated with license renewal may affect terrestrial communities. Application of best management practices would reduce the potential for impacts. The magnitude of impacts would depend on the nature of the activity, the status of the resources that could be affected, and the effectiveness of mitigation." 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 28

Non-cooling system impacts to terrestrial resources could result from refurbishment or from activities such as landscape maintenance and infrastructure upgrades. The NRC made non-cooling system impacts to terrestrial resources a Category 2 issue because the significance of impacts on terrestrial habitats and wildlife would depend on site-specific factors (NRC 2013b). Aspects of the site and project to be ascertained are: (1) the nature of refurbishment activities, (2) the identification of important ecological resources, and (3) the extent of impacts to terrestrial plant and animal habitats.

As discussed in Section 2.3, no refurbishment activities are necessary or planned for the LSCS period of extended operation.

Wildlife and plant species on the developed parts of the LSCS property are common species adapted to industrial sites and able to tolerate industrially-generated noise and human activity. The characteristics of terrestrial communities on less developed property near the protected area are the result of the effects of years of operations and maintenance programs on those communities. Operations and maintenance activities during the license renewal term are expected to be similar to current activities. Furthermore, existing procedures consider impacts to nearby resources as part of the planning process, and NRC has determined that the effects of noise would be small at all plants. As a result, current operations and maintenance have small impacts on terrestrial resources. Therefore, Exelon Generation concludes that continued operations and maintenance activities associated with non-cooling systems would have SMALL impacts on terrestrial resources and warrant no additional mitigation measures.

4.6.2.2 Water Use Conflicts with Terrestrial Resources (Plants with Cooling Ponds or Cooling Towers Using Makeup Water from a River)

NRC

> **"If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river, an assessment of the impact of the proposed action on water availability and competing water demands, the flow of the river, and related impacts on…riparian (terrestrial) ecological communities must be provided…" 10 CFR 51.53(c)(3)(ii)(A).**
>
> **"Impacts on terrestrial resources in riparian communities affected by water use conflicts could be of moderate significance." 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 33**

This issue pertains to the effects of water use conflicts on terrestrial resources in riparian communities, and applies to nuclear power plants with cooling ponds or cooling towers, typically with high levels of consumptive use, and that use makeup water from a river. Water use conflicts with terrestrial resources in riparian communities could occur when water that supports these resources is diminished either because of droughts; increased water demand for agricultural, municipal, or industrial usage; or a combination of such factors. Because water use circumstances vary from site to site, the NRC concluded that the impact of water use conflicts with riparian communities is a plant-specific Category 2 issue (NRC 2013b).

As discussed in Section 3.7, wildlife species in the vicinity of the LSCS site are those typically found in similar habitats in northeastern Illinois and the Midwest. No wildlife or plant species in the vicinity are restricted to or dependent upon riparian communities.

LSCS withdraws water for condenser cooling from a large cooling pond that receives its makeup water from the Illinois River. Section 4.1 discusses the impacts to the Illinois River of the plant's average and maximum makeup water withdrawal rates and concludes that LSCS operations during the license renewal term would not limit the availability of water in the Illinois River. Section 4.5.2.2 discusses impacts to the alluvial aquifer. LSCS uses less than 378 L/min (100 gpm) from the Cambrian Ordovician Aquifer. Groundwater use by LSCS has no effect on groundwater levels in the alluvial aquifer because the alluvial aquifer is not in hydraulic contact with the Cambrian-Ordovician Aquifer, and the site groundwater wells pump such a small volume of water.

In conclusion, impacts on riparian communities would be SMALL over the license renewal term and require no mitigation measures beyond those already in place because (1) withdrawal of Illinois River water for cooling pond makeup has almost no effect on river flow or elevation during normal and high-flow periods, (2) the LSCS Extreme Heat Implementation Plan would mitigate most potential impacts from makeup water withdrawals during drought conditions (discussed in Section 4.1), and (3) LSCS groundwater use has no impact on the alluvial aquifer.

4.6.3 Aquatic Resources

4.6.3.1 Impingement and Entrainment of Aquatic Organisms (Plants with Once-Through Cooling Systems or Cooling Ponds)

NRC

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

"The impacts of impingement and entrainment are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems, depending on cooling system withdrawal rates and volumes and the aquatic resources at the site." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 36

The NRC made impacts to fish and shellfish from impingement and entrainment a Category 2 issue because it could not assign a single significance level to the issue for all nuclear power plant sites. The impacts of impingement and entrainment are small at many plants, but they may be moderate or large at others, particularly those with once-through cooling systems. Information needing to be ascertained includes: (1) whether cooling system is once-through or closed cycle, and (2) status of Clean Water Act (CWA) Section 316(b) determination or equivalent state documentation.

LSCS is one of eight U.S. nuclear power plants with a cooling pond-based heat dissipation system and one of seven with a freshwater cooling pond (NRC 2013b). Makeup water for the LSCS cooling pond is withdrawn from the Marseilles Pool in the Illinois River via an intake structure (river screen house) equipped with three makeup pumps, each with a capacity of 114,000 L/min (30,000 gpm) (NRC 1978; Exelon Nuclear 2012a). The river screen house is also equipped with a trash rack and conventional vertical travelling screens. When the cooling pond is at or near full pool, only one or two pumps are required to maintain the pond's water level (NRC 1978). Velocities in the short intake channel range from 0.1 to 0.2 m/second (0.3 to 0.5 ft/second) with one pump operating to 0.2 to 0.3 m/second (0.6 to 1.0 ft/second) with two pumps operating, depending on river level (NRC 1978). The velocity at the face of the travelling screens is 0.2 m/second (0.5 ft/second) during one pump operation and 0.3 m/second (0.9 ft/second) during "occasional" operation (NRC 1978).

Section 316(b) of the CWA requires that any standard established pursuant to Sections 301 or 306 of the CWA shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impacts (33 USC 1326). Impingement of juvenile and adult fish on intake screens that protect the condenser cooling system is a potential adverse environmental impact that can be minimized by the BTA; entrainment of early life stages of fish and shellfish (eggs and larvae) into and through the condenser cooling system is another.

The NRC evaluated potential impacts of the LSCS cooling system in the Final Environmental Statement related to the operation of LaSalle County Station, Units 1 and 2 (NRC 1978). NRC staff observed at that time that the annual average amount of water withdrawn from the Illinois River for cooling pond makeup would be around 1 percent of the typical flow, or 3 percent of the 7Q10 (extreme low) flow (NRC 1978). They noted that intake velocities at the face of the travelling screens were expected to be 0.2 m/second (0.5 ft/second) 93 percent of the time the Station was operating and 0.3 m/ second (0.9 ft/second) the remaining 7 percent of the time. Because of the small volume of makeup water required and the low intake velocities expected, the NRC concluded that impingement and entrainment impacts would be "minor" (NRC 1978). The LSCS Unit 1 Operating License Appendix B—Environmental Protection Plan, issued in 1982, indicated that NRC would rely on Illinois EPA to regulate operational impingement and entrainment monitoring. In 1979, the IEPA issued LSCS an NPDES permit with a condition requiring impingement and entrainment monitoring and preparation of a Clean Water Act, Section 316(b) Demonstration Report. However, when the IEPA renewed the permit in 1984, this requirement was removed, presumably because in 1979 a Federal Court remanded the 1976 federal regulations that required monitoring.

The IEPA renewed the NPDES permit for LaSalle County Station (No. IL0048151) on July 5, 2013. The permit expires on July 31, 2018. The permit includes Special Condition 15, which relates to potential impacts from cooling water intake. It reads as follows:

> "The facility utilizes a closed-cycle recirculating cooling system, a 2058 acre cooling pond, for cooling of plant condensers and is determined to be the equivalent of Best Technology Available (BTA) for cooling water intake structures to prevent/minimize impingement mortality in accordance with the Best Professional Judgment (BPJ) provisions of 40 CFR 125.3 because it allows the facility to only withdraw the amount of water necessary to maintain the cooling pond level rather than the entire volume used for cooling of the plant condensers."

The permit makes no specific mention of entrainment, but the design and operational features of the plant that limit impingement mortality, and in particular the small volume of cooling pond makeup water required, also minimize entrainment losses.

The LSCS NPDES permit calls for LSCS to "prepare and submit information to the Agency [IEPA] outlining current intake structure conditions, including a detailed description of the current intake structure operation and design, description of any operational or structural modifications from original design parameters, and source waterbody flow information as necessary." LSCS submitted the required information on January 30, 2014.

The NPDES permit constitutes the current CWA Section 316(b) determination that the cooling water intake structure represents BTA. This determination is supported by (1) the closed-cycle design of the LSCS cooling system, which requires a modest amount of water for cooling pond makeup, (2) intake velocities that are typically 0.2 m/second (0.5 ft/second); (3) a predictive 316(b) Demonstration Study completed in 1976 and used by NRC to assess impingement and entrainment impacts as part of the original licensing process, and (4) almost 30 years of fisheries monitoring in the Illinois River (Marseilles Pool) that show no plant- or intake-related impacts. Therefore, the impacts of impingement and entrainment are SMALL and warrant no additional mitigation. EPA published revised Clean Water Act 316(b) regulations on August 15, 2014 (79 FR 48300-48439) but they do not affect the existing determination in the LSCS NPDES permit.

As Section 2.2.3 indicates, the LSCS cooling pond is a wastewater treatment works (35 IAC 301.415), and as such it is excepted from the definition of "waters of the state" (35 IAC 301.440) as well as the definition of "waters of the United States" under the federal Clean Water Act

(40 CFR 230.3(s)). As a result, assessment of entrainment or impingement effects at the cooling pond's lake screen house is not required, and no studies of such effects have been performed.

4.6.3.2 Thermal Impacts on Aquatic Organisms (Plants with Once-Through Cooling Systems or Cooling Ponds)

NRC

> **"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations and, if necessary, a 316(a) variance in accordance with 40 CFR 125, or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from thermal changes …." 10 CFR 51.53(c)(3)(ii)(B)**
>
> **"Most of the effects associated with thermal discharges are localized and not expected to affect overall stability of populations or resources. The magnitude of impacts, however, would depend on site-specific thermal plume characteristics and the nature of aquatic resources in the area." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 39**

The NRC made impacts on fish and shellfish from thermal discharges a Category 2 issue, because the significance of impacts at a given plant depends on cooling system design, plant operating characteristics, configuration of the thermal plume (both horizontal [surface area] and vertical [depth]), and characteristics of the potentially affected aquatic resources (NRC 2013b). Thermal impacts may therefore be small, moderate, or large, depending on site-specific circumstances. As a general rule, plants with once-through cooling systems produce greater thermal impacts than plants with recirculating, closed-cycle cooling systems, but other factors may come into play, such as the bathymetry of the receiving stream or the presence/absence of rare or sensitive aquatic species.

Information to be ascertained includes: (1) whether the cooling system is once-through or closed-cycle, (2) whether the facility meets state water quality standards and effluent limits with respect to temperature, and (3), if it does not, evidence of a CWA Section 316(a) thermal variance or equivalent state documentation.

Section 316(a) of the CWA establishes a process whereby a thermal effluent discharger can demonstrate that thermal discharge limitations are more stringent than necessary (to ensure the protection and propagation of balanced, indigenous populations of fish and wildlife in and on the receiving waters) and get regulatory-agency approval of facility-specific thermal discharge limits (33 USC 1326).

If a discharger is able to meet applicable state water quality standards/temperature limits, then no thermal variance is necessary. Plants with once-through cooling systems that discharge to streams and rivers almost always require thermal variances; plants with cooling pond-based systems, such as LSCS, often do not.

The state of Illinois' water quality standards for temperature are found at Section 302.11 of Title 35 ("Environmental Regulations for the State of Illinois") of the Illinois Administrative Code and include the maximum allowable temperature rise above ambient temperature (2.8°C/5.0°F) and maximum allowable temperatures “at representative locations in the main river” (outside of a mixing zone) during any month (16°C/60°F December-March; 32°C/90°F April-November).

As described in Section 2.2.3, makeup water for the LSCS cooling pond is withdrawn from the Illinois River at an intake structure (river screen house) approximately 5.6 km (3.5 mi) north of the LSCS cooling pond. The screen house is equipped with three makeup pumps, each with a capacity of 114,000 liters/min (30,000 gpm) (NRC 1978). To prevent the buildup of solids in the cooling pond, water is continuously released (as blowdown) from the cooling pond and replaced with river water. Blowdown is discharged from the cooling pond to the Illinois River via a canal, a pipe, a plunge pool, and an open, rip-rap-lined channel that is approximately 300 m (1,000 ft) downstream of the river intake structure. As described in Section 2.2.3, the cooling pond is defined as a wastewater "treatment works" (35 IAC 301.415), and as such it is excepted from the definition of “waters of the state” (35 IAC 301.440) as well as the definition of “waters of the United States” under the federal Clean Water Act (40 CFR 230.3(s)). As a result, the water inventory within the cooling pond is not subject to state water quality standards.

In its FES for LSCS’s operation, the NRC staff calculated expected discharge temperatures in blowdown to the Illinois River, and modeled the size and extent of the thermal plume in the river using highly conservative inputs (e.g., 100 percent load factor, maximum blowdown rate, low [7Q10] river flow). With regard to discharge impacts to biota, the NRC staff predicted that under worst-case conditions (highest blowdown temperature) the thermal plume area (defined by the 3°C/5°F isotherm) would be 2,500 m^2 (0.6 ac) and would encompass approximately 9 percent of the river’s cross section. This would leave a large zone of passage for fish, allowing them to move freely up and down-river. They concluded by saying “staff expects the discharge impacts to be minimal and of little influence on the natural biotic populations.”

The LSCS NPDES permit contains, as Special Condition 3, a 2.8°C (5.0°F) limit on the maximum temperature rise above natural temperature (“Delta-T”) and seasonal limits on discharge temperatures (16°C [60°F] from December through March; 32°C [90°F] from April through November). These temperature limits mirror the limits set forth in Section 302.211(d) and Section 302.211(e), respectively, of Title 35 (“Environmental Regulations for the State of Illinois”) of the Illinois Administrative Code.

Because LSCS typically is able to meet these temperature limits (and has an Extreme Heat Implementation Plan as described in Section 4.5.1 for extreme climate conditions), the IEPA, has not required Exelon Generation to conduct a thermal effects study or seek a Section 316(a) thermal variance for LSCS. No such variance is required because the plant’s discharges are in compliance with state water quality standards.

Based on the fact that LSCS’s thermal discharges comply with applicable state water quality standards, affect a very small area of the Illinois River, and do not create a barrier to up- and downstream fish movement, Exelon Generation concludes that thermal impacts to aquatic organisms over the license renewal term would continue to be SMALL and would not warrant additional mitigation.

As described in Section 3.7.1.5 LSCS Cooling Pond, IDNR and Exelon Generation provide a thermally-tolerant recreational fishery in the LSCS cooling pond. Four reportable fish kills have occurred in the cooling pond since 2001 (Section 3.7.1.5 LSCS Cooling Pond). However, because the LSCS cooling pond is a waste water treatment works, assessment of thermal effects on fish and shellfish resources within the cooling pond is not required, no studies of such effects have been conducted, and no additional mitigation beyond that described in section 3.7.1.5 is warranted.

4.6.3.3 Water Use Conflicts with Aquatic Resources (Plants with Cooling Ponds or Cooling Towers Using Makeup Water from a River)

NRC

> **"If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river, an assessment of the impact of the proposed action on water availability and competing water demands, the flow of the river, and related impacts on stream (aquatic)… ecological communities must be provided…" 10 CFR 51.53(c)(3)(ii)(A).**
>
> **"Impacts on aquatic resources in stream communities affected by water use conflicts could be of moderate significance in some situations." 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 46**

Surface water use conflicts may occur when plants with closed-cycle cooling systems withdraw makeup water from rivers experiencing reduced flows, whether the reduction in flow is caused by drought or as the result of increased use of the surface water by additional agricultural, municipal, or industrial users. Reduced river flows associated with climate or increased water use could in turn affect the quantity and quality of stream habitat that is available to aquatic communities. Because the extent of surface water use conflicts varies from location to location, as do the potential impacts arising from these conflicts, the NRC concluded that the impact of water use conflicts on aquatic communities could not be determined generically (NRC 2013b). The impact of surface water use conflicts on stream communities is therefore a plant-specific Category 2 issue.

As discussed in Section 2.2.3, condenser cooling water for the LSCS plant is withdrawn from an 833 ha (2,058-ac) cooling pond. Makeup water is pumped to the cooling pond from the Illinois River. Section 4.5.1 describes the plant's average and maximum makeup rates and compares these to historical flows in the Illinois River. Under normal circumstances (average withdrawal rate), consumptive use (water lost to evaporation and seepage) is less than 0.5 percent of the river's 92-year annual average mean flow. The maximum withdrawal rate (all three makeup pumps operating at capacity), would withdraw approximately 1.8 percent of the river's 92-year annual average mean flow. Because withdrawal from Illinois River for cooling pond makeup has almost no effect on river level during normal or higher flows, and because withdrawals during low-flow periods are managed in accordance with the LSCS Extreme Heat Implementation Plan (discussed in Section 4.5.1) impacts on aquatic communities would continue to be SMALL over the license renewal term and require no mitigation measures beyond those already in place.

4.6.4 Special Status Species and Habitats

4.6.4.1 Threatened, Endangered, and Protected Species and Essential Fish Habitat

NRC

> **"All license renewal applicants shall assess the impact of refurbishment, continued operations, and other license-renewal-related construction activities on important plant and animal habitats. Additionally, the applicant shall assess the impact of the proposed action on threatened and endangered species in accordance with Federal laws protecting wildlife, including but not limited to, the Endangered Species Act, and essential fish habitat in accordance with the Magnuson-Stevens Fishery Conservation and Management Act." [10 CFR 51.53(c)(3)(ii)(E)]**
>
> **"The magnitude of impacts on threatened, endangered, and protected species, critical habitat, and essential fish habitat would depend on the occurrence of listed species and habitats and the effects of power plant systems on them. Consultation with appropriate agencies would be needed to determine whether special status species or habitats are present and whether they would be adversely affected by continued operations and refurbishment associated with license renewal." (10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 50)**

The NRC made impacts to threatened and endangered species a Category 2 issue because the status of these species is subject to change, and a site-specific assessment is required to determine whether any identified species could be affected by refurbishment activities or continued plant operations during the renewal period. In addition, compliance with the Endangered Species Act requires consultation with appropriate federal agencies to determine whether threatened or endangered species are present and whether they would be adversely affected by the continued operation of the nuclear plant or refurbishment of facilities during the license renewal term.

The NRC requires applicants seeking to renew operating licenses of nuclear plants that could affect coastal resources to evaluate potential impacts of license renewal on marine and estuarine fish species for which Essential Fish Habitat has been identified. Neither any species with a Fishery Management Plan nor any Essential Fish Habitat is found in Illinois or the Midwestern U.S., and LSCS is not listed in the 2013 GEIS as one of the 17 nuclear plants for which Essential Fish Habitat "may be a consideration" (NRC 2013b).

With the exception of the species identified in Section 3.7, Exelon Generation is not aware of any protected eagles or threatened or endangered species that could occur at, or in the vicinity of, LSCS. Current operations do not affect protected eagles or any listed species or their habitats. Furthermore, Station operations are not expected to change over the license renewal term. Therefore, no adverse impacts to protected eagles or threatened or endangered species from current or future operations are anticipated. As discussed in Section 2.3, no refurbishment or license-renewal-related construction is planned, so there is very little potential for construction-related impacts to listed or protected species in the area of LSCS over the license renewal period. Furthermore, federal and state laws protect threatened and endangered species. State and federal resource agencies contacted by Exelon (see Appendix D) evidenced no concern about license renewal impacts. Given that (1) no federally listed species have been observed on the LSCS property, (2) no changes in operations are expected over the license renewal term, (3) no major construction or refurbishment projects are planned, and (4) resource agencies contacted voiced no concerns about the continued operation of LSCS, Exelon concludes that renewal of the LSCS operating licenses is NOT LIKELY TO ADVERSELY AFFECT an individual or the population of any federally listed species or its critical habitat and no additional mitigation is warranted.

4.7 Historic and Cultural Resources

NRC

> **"All applicants shall identify any potentially affected historic or archeological properties and assess whether any of these properties will be affected by future plant operations and any planned future refurbishment activities in accordance with the National Historic Preservation Act" 10 CFR 51.53(c)(3)(ii)(K)**
>
> **"Continued operations and refurbishment associated with license renewal are expected to have no more than small impacts on historic and cultural resources located onsite and in the transmission line ROW because most impacts could be mitigated by avoiding those resources. The National Historic Preservation Act (NHPA) requires the Federal agency to consult with the State Historic Preservation Officer (SHPO) and appropriate Native American Tribes to determine the potential effects on historic properties and mitigation, if necessary." 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 51**

The NRC made impacts to historic and cultural resources a Category 2 issue. Determinations of impacts to historic and cultural resources are site-specific in nature and the National Historic Preservation Act mandates that impacts must be determined through consultation with the State Historic Preservation Office (NRC 2013b).

In the context of the National Historic Preservation Act, the NRC has determined that the area of potential effect for license renewal is the area that could be impacted by land-disturbing or other operational activities associated with continued plant operations and maintenance during the license renewal term or refurbishment. The area of potential effect typically encompasses the plant site, its immediate environs including the viewshed, and the transmission lines within the scope of the review (NRC 2013b).

Exelon Generation is not aware of any historic or cultural resources that have been affected by LSCS operations. The Illinois Archaeological Survey (IAS) completed a Phase I Archaeological Survey of the LSCS site (originally proposed as the Collins Generating Station) in 1972 and concluded that the construction of the facility would have no significant impact on archaeological resources. The Final Environmental Statement relating to the operation of LSCS stated that there are no historical or cultural sites recorded in the National Registry of National Landmarks, as supplemented 8 June 1976, or the National Register of Historic Places, as supplemented 3 January 1978, as being on the LSCS site (NRC 1978). Operation and maintenance of the Station has not resulted in any negative impacts to previously recorded archaeological sites described in Section 3.8.

In addition, proposed changes to a plant activity at LSCS are subject to a screening process to determine whether the actual or potential environmental impacts of the proposed change are either bounded by the station's environmental basis or can be avoided using practical, available alternatives. If neither of these circumstances exist, then consultation would be initiated with the State Historic Preservation Officer (SHPO) to determine what measures would be needed to minimize and mitigate the impacts. Any measures resulting from consultation with the SHPO would be incorporated into the work plan for the land-disturbing activity.

Because (1) past operations have not affected any historic or cultural resource, (2) Exelon Generation has procedures to protect undiscovered resources from future potential impacts, and (3) the Illinois SHPO voiced no concerns about continued operation of the LaSalle County Station (see Appendix E), Exelon concludes that HISTORIC PROPERTIES ARE PRESENT, BUT NOT ADVERSELY AFFECTED by renewal of the LSCS operating licenses and no additional mitigation is warranted.

4.8 Socioeconomics

The following Category 1 socioeconomic topics were reviewed for new and significant information at LSCS that could make the generic finding for a resource as described in the 2013 GEIS inapplicable:

- Employment, income, recreation and tourism
- Tax revenues
- Community service and education
- Population and housing
- Transportation

No new and significant information was identified, therefore the conclusions regarding impacts to socioeconomics in the GEIS are considered appropriate for the LSCS license renewal term and impacts to socioeconomic topics do not need further analysis. Section 3.9 discusses the socioeconomics the region.

4.9 Human Health

4.9.1 Microbiological Hazards to the Public

NRC

> **"If the applicant's plant uses a cooling pond, lake, or canal or discharges into a river, an assessment of the impact of the proposed action on public health from thermophilic organisms in the affected water must be provided." 10 CFR 51.53(c)(3)(ii)(G)**
>
> **"These organisms are not expected to be a problem at most operating plants except possibly at plants using cooling ponds, lakes, or canals, or that discharge into rivers. Impacts would depend on site-specific characteristics. " 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 60**

The NRC designated impacts to public health from microbiological hazards a Category 2 issue, requiring plant-specific analysis, because the magnitude of the potential public health impacts associated with thermal enhancement of such organisms' habitats, particularly those of *Naegleria fowleri*, could not be determined generically. NRC requires [10 CFR 51.53(c)(3)(ii)(G)] an assessment of the potential impact of thermophilic organisms in receiving waters on public health if a nuclear power plant uses a cooling pond, cooling lake, or cooling canal or discharges to a river.

As previously discussed, Exelon Generation is authorized under NPDES permit No. IL0048151 to discharge cooling pond blowdown to the Illinois River. The public potentially can be exposed to *Naegleria* in either the Illinois River or the cooling pond, most of which is managed by the IDNR as a recreational resource. As described more fully in Section 3.10.1, the probability of a *Naegleria* infection in the Illinois River is low for the following reasons: (1) the area of the thermal discharge mixing zone is small compared to the size of the river in the discharge area, (2) the duration in which heated effluent is allowed to exceed critical temperatures is limited, and (3) the Illinois Department of Public Health has stated (as of June 2013) that there has never been a case of *Naegleria* infection reported in Illinois (IDPH 2013b).

Section 3.10.1 further concludes that infection by thermophilic microorganisms in the cooling pond has a low-probability of occurring because no swimming, wading, water-skiing or sailing are allowed, thus, eliminating the nasal exposure pathway.

Exelon Generation concludes that the risk to public health from human exposure to thermophilic organisms resulting from operation of LSCS is SMALL and does not warrant mitigation. Exelon Generation requested information from the Illinois Department of Public Health on any concerns the agency may have relative to thermophilic organisms in the LSCS cooling pond or the Illinois River near the blowdown. Both the Illinois Department of Public Health and the IEPA acknowledged Exelon Generations' request for information and indicated that they have no expertise regarding the topic (IEPA 2014b, IDPH 2014).

4.9.2 Electric Shock Hazards

NRC

> **The environmental report must contain an assessment of the impact of the proposed action on the potential shock hazard from transmission lines "...[i]f the applicant's transmission lines that were constructed for the specific purpose of connecting the plant to the transmission system do not meet the recommendations of the National Electric Safety Code for preventing electric shock from induced currents…" 10 CFR 51.53(c)(3)(ii)(H)**
>
> **"Electrical shock potential is of small significance for transmission lines that are operated in adherence with the National Electrical Safety Code (NESC). Without a review of conformance with NESC criteria of each nuclear power plant's in-scope transmission lines, it is not possible to determine the significance of the electrical shock potential." 10 CFR Part 51, Subpart A, Table B 1, Issue 64**

Section 3.10.2 explains that the offsite transmission lines connected to the LSCS switchyard are not in-scope transmission lines as defined by footnote 4 of Table B-1 of 10 CFR Part 51, Subpart A. Also, the electrical connections between the main plant and the LSCS switchyard traverse only property used for industrial purposes. Because electrical shock hazards are controlled on the LSCS site in accordance with applicable industrial safety standards and potentially affected workers comply with electrical safety procedures when working near energized equipment, Exelon Generation concludes that onsite electrical shock potential is of SMALL significance and no additional mitigation is warranted.

4.10 Environmental Justice

4.10.1 Minority and Low-Income Populations

NRC

> **"Applicants shall provide information on the general demographic composition of minority and low-income populations and communities (by race and ethnicity) residing in the immediate vicinity of the plant that could be affected by the renewal of the plant's operating license, including any planned refurbishment activities, and ongoing and future plant operations. " 10 CFR 51.53(c)(3)(ii)(N)**
>
> **"Impacts to minority and low-income populations and subsistence consumption resulting from continued operations and refurbishment associated with license renewal will be addressed in plant-specific reviews. See NRC Policy Statement on the Treatment of Environmental Justice Matters in NRC Regulatory and Licensing Actions (69 FR 52040; August 24, 2004). " 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 67**

The NRC designated impacts to minority and low-income populations a Category 2 issue, requiring plant-specific analysis, because the magnitude of the potential impacts could not be determined generically. NRC requires an assessment of the potential impacts on minority and low-income populations, including populations engaged in subsistence-like living, from continued operation of the Station and any planned refurbishment activities. LSCS has no plans for refurbishment.

A presidential Executive Order (12898) directs all Federal agencies to consider in their programs, policies, and activities any "disproportionately high and adverse human health or environmental effects" on minority or low-income populations.

Chapter 4 evaluates the impacts of continued operation of LaSalle County Station on the environment, including the population within an 80-km (50-mi) radius. All activities associated with the continued operation have been determined to have SMALL or non-adverse impacts during the license renewal term. Therefore, high or adverse impacts to the general human population would not occur. Section 3.11 identifies the locations of minority and low-income populations as defined by the NRC Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues (NRC 2009). Section 3.11 also describes the search for subsistence-like populations near LSCS, of which none were found.

The figures accompanying Section 3.11 show the locations of minority and low-income populations within 80 km (50 mi) of LSCS. None of those locations, when considered in the context of impact pathways described in Chapter 4, is expected to be disproportionately impacted. Each location is sufficiently distant from the Station to not present a focal point of impacts that would be disproportionate compared to other locations.

Hence, Exelon Generation concludes that the occurrence of disproportionately high and adverse impacts to minority and low-income populations would be SMALL and no mitigation is warranted.

4.11 Waste Management

The following Category 1 waste management issues were reviewed for new and significant information at LSCS that could make the generic finding for a resource as described in the 2013 GEIS inapplicable:

- Low-level waste storage and disposal
- On-site storage of spent nuclear fuel
- Mixed waste storage and disposal
- Non-radioactive waste storage and disposal

No new and significant information was identified, therefore the conclusions regarding impacts to waste management in the GEIS are considered appropriate for the LSCS license renewal and impacts to waste management do not need further analysis. Section 2.2.2 discussed spent fuel characteristics and storage. Section 2.2.7 describes radioactive wastes other than spent fuel that are generated during plant operations. Section 2.2.8 describes the non-radioactive wastes generated during plant operations. Section 3.12 discusses the various waste management systems. The assessment of LSCS fuel is discussed in Section 4.13.

4.12 Cumulative Impacts

NRC

> **"Applicants shall provide information about past, present, and reasonably foreseeable future actions occurring in the vicinity of the nuclear plant that may result in a cumulative effect. " 10 CFR 51.53(c)(3)(ii)(O)**
>
> **"Cumulative impacts of continued operations and refurbishment associated with license renewal must be considered on a plant-specific basis. Impacts would depend on regional resource characteristics, the resource-specific impacts of license renewal, and the cumulative significance of other factors affecting the resource. " 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 73**

This section considers the contribution of the continued operation of LSCS to potential regional environmental cumulative impacts. It assesses the potential significance of LSCS impacts in relation to other known or reasonably foreseeable projects. A cumulative impact is defined in the Council of Environmental Quality regulations (40 CFR 1508.7) as an "impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (federal or non-federal) or person undertakes such other actions."

In this section, past, present, and reasonably foreseeable future actions that are federally authorized or funded and take place in the vicinity of LSCS are identified and possible cumulative effects are discussed. For the purposes of this analysis, past and present actions include actions up to and including the time that the LSCS License Renewal Application was submitted to the NRC. Reasonably foreseeable future actions are those that are ongoing (and will continue into the future), are funded for future implementation, or are included in firm, near-term plans covering the 20-year period of extended operation. The geographic area affected by cumulative impacts depends on the resource being considered (NRC 2013c). Past, present and reasonably foreseeable actions may include individually minor but collectively significant actions occurring over a period of time (NRC 2013c).

The 80-km (50-mi) radius for LSCS for considering severe accidents, air quality, and radiological health impacts to the public intersects the 80-km (50-mi) radii of five other nuclear power plants: Braidwood, Dresden, Byron, Clinton, and Quad Cities. Two of those, Braidwood and Dresden are within 80 km (50 mi) of LSCS.

The Upper Illinois/Mazon River watershed has 148 NPDES-permitted facilities, including LSCS, Braidwood Generating Station and Dresden Generating Station (IEPA 2009). Dresden has a cooling pond that withdraws makeup water from the Kankakee River and that discharges blowdown to the Illinois River immediately downstream of the confluence of the Kankakee and Des Plaines Rivers. The Braidwood cooling pond withdraws water from the Kankakee River and its blowdown discharges to the Kankakee. Braidwood is further upstream on the Kankakee than Dresden.

Other significant electrical power generation sources in LaSalle County are Invenergy LLC's Grand Ridge facility capable of 210 MW of wind-generated power, and 20 MW of solar-generated power; the GSG wind farm with 80 MW (in Lee and LaSalle Counties); and the Top Crop wind farm with 102 MW (in LaSalle, Grundy and Livingston Counties).

The 2014 LaSalle County Comprehensive Land Use Plan (LEAMgroup and LaSalle County 2014) does not identify any specific development or major commercial projects that are planned in the county for the next "five years or more."

As noted in Section 4.1 LSCS will have a SMALL impact on land use and visual resources during the license renewal term and therefore, will not contribute to cumulative impacts to land use or visual resources. As described in Section 3.3 LaSalle County is designated as an attainment area for all NAAQS. As noted in Section 4.2 LSCS will have a SMALL impact on air quality during the license renewal term and therefore, will not contribute to cumulative impacts to the region's air quality. As noted in Section 4.3 LSCS will have a SMALL impact on geology and soils during the license renewal term and therefore, will not contribute to cumulative impacts to the region's geology or soils.

4.12.1 Water Resources

Surface Water Use

As described in Section 4.5.1, impacts from the LSCS license renewal on surface water use would be SMALL, and would not warrant mitigation. This determination was arrived at by considering effects from existing water users with intakes on the Marseilles Pool and overall planning efforts for the Illinois River. Accordingly, because the result presented in Section 4.5.1 is a cumulative analysis, LSCS's contribution to cumulative surface water use would be SMALL, as indicated therein.

Groundwater Use

As described in Section 4.5.2.2, LSCS uses less than 378 L/min (100 gpm) of groundwater and thus, would not create an offsite cone of depression. The closest public water supply well is approximately 10 km (6 mi) northwest of the site. Groundwater use by LSCS has no effect on groundwater levels in the alluvial aquifer because the alluvial aquifer is not in hydraulic contact with the Cambrian-Ordovician Aquifer. The net consumptive use of the river is less than 0.5 percent of the river's 92-year annual average mean flow and therefore has no effect on the river water level or the alluvial aquifer (Section 4.6.2.2). Therefore LSCS's contribution to cumulative groundwater use would be SMALL.

Groundwater Quality

As discussed in Section 4.5.2.3, the impact of license renewal on groundwater quality would be SMALL and would not warrant mitigation. Seepage from the cooling pond is not expected to impact the Cambrian-Ordovician Aquifer due to thick clay sediments that effectively isolate the aquifer from the cooling pond. Shallow aquifer degradation due to LSCS activities is being mitigated and has no impact beyond the plant boundaries. Therefore LSCS's contribution to cumulative impacts to groundwater quality would be SMALL.

4.12.2 Ecological Resources

4.12.2.1 Terrestrial Resources

As described in Section 4.6.2, the impacts of the LSCS license renewal on terrestrial resources would be SMALL and would not warrant mitigation. Wildlife and plant species on the developed parts of the LSCS property are common species adapted to industrial sites and able to tolerate relatively high levels of noise and human activity. The characteristics of terrestrial communities on less developed property outside the protected area reflect the communities' adaptations to the activities at LSCS which are not expected to change during the license renewal term.

Because the withdrawal of Illinois River water for cooling pond makeup has almost no effect on river flow or level during normal or higher flows, and the LSCS Extreme Heat Implementation Plan would mitigate potential impacts from makeup water withdrawals during drought conditions, and because LSCS groundwater use has no impact on the alluvial aquifer, impacts to riparian communities from LSCS's continued operation would be SMALL and would not warrant mitigation.

Therefore, Exelon Generation concludes that LSCS's contribution to cumulative effects on terrestrial resources would be SMALL.

4.12.2.2 Aquatic Resources

As described in Section 4.6.3, the impacts of the LSCS license renewal on aquatic resources from thermal effects, entrainment, impingement, or water use conflicts would be SMALL and would not warrant mitigation.

Section 3.7 identifies water quality impairments in the Illinois River that could potentially affect aquatic resources; however, LSCS does not measurably contribute to these impairments. Surface water quality impacts from nuclear plants is a Category 1 issue with SMALL impacts (10 CFR 51.53).

The NPDES permit (No. IL0048151) for v constitutes the current CWA Section 316(b) determination that the cooling water intake structure represents the Best Technology Available. This determination is supported by the closed-cycle design of the LSCS cooling system which minimizes adverse effects with a modest amount of water for cooling pond makeup, intake velocities that are typically 0.2 m/second (0.5 ft/second); and almost 30 years of fisheries monitoring in the Illinois River (Marseilles Pool) that show no plant- or intake-related impacts. Therefore, the impacts of impingement and entrainment are SMALL and warrant no additional mitigation.

LSCS's thermal discharges comply with applicable state water quality standards, affect a very small area of the Illinois River, and do not create a barrier to up- and downstream fish movements. Because these thermal discharges are not expected to change significantly as a result of license renewal, thermal impacts to aquatic organisms over the license renewal term would continue to be SMALL and would not warrant additional mitigation.

Because the withdrawal of Illinois River water for cooling pond makeup has almost no effect on river flow or level during normal and higher flows, and the LSCS Extreme Heat Implementation Plan would mitigate potential impacts from makeup water withdrawals during droughts, impacts to aquatic communities from LSCS's continued operation would be SMALL and would not warrant mitigation.

Therefore, Exelon Generation concludes that LSCS's contribution to any cumulative effects on aquatic resources would be SMALL.

4.12.2.3 Special Status Species and Habitats

Table 3.7.2-1 lists the endangered or threatened species recorded in LaSalle County. None except the state-listed peregrine falcon have been reported from LSCS property. The bald eagle, which is protected under the Bald and Golden Eagle Protection Act was reported from the site in the 1970s, however, none have been reported in recent years. No federally designated critical habitat has been established in LaSalle County for any protected species. Furthermore, federal and state laws protect threatened or endangered species. Neither species with a Fishery Management Plan, nor any Essential Fish Habitats are found in Illinois.

Generally, operating nuclear facilities do not incur significant wildlife mortality and Exelon Generation has no record of wildlife mortality at LSCS. Exelon concludes that renewal of the LSCS operating licenses is NOT LIKELY TO ADVERSELY AFFECT an individual or population of any federally listed species or its critical habitat.

Because the renewal of the LSCS licenses has been determined NOT LIKELY TO ADVERSELY AFFECT any protected species, LSCS's continued operation also would not contribute to adverse cumulative impacts to these species.

4.12.3 Historic and Archeological Resources

As discussed in Section 4.7, no refurbishment activities or construction of license renewal-related facilities are planned at LSCS during the license renewal term. LSCS has procedures to protect previously unknown historic or cultural resources that may be discovered on the site. No sites listed on the National Register of Historic Places that are located within 10 km (6 mi) of LSCS (Table 3.8-2) are also are within the LSCS viewshed. Hence, LSCS's continued operation would not contribute to cumulative adverse impacts on historic and cultural resources.

4.12.4 Human Health

4.12.4.1 Non-radiological Health Impacts

Potential non-radiological cumulative health impacts could include local impacts from fugitive dust and vehicle emissions, occupational injuries, noise, and vehicle accidents during the transport of materials or commuting. However, license renewal would not involve construction or refurbishment, so LSCS would not be a source of fugitive dust or construction noise. Site-specific impacts from vehicle emissions, occupational injuries, noise from operations, and traffic and transportation impacts were not evaluated in this environmental report because such impacts already have been determined by NRC to be SMALL for all nuclear plant sites. Therefore, Exelon Generation concludes that LSCS's contribution to cumulative adverse non-radiological human health impacts would be SMALL.

The potential for exposure to microbiological agents was considered in Section 4.9.1. LSCS discharges heated effluent from the reactor cooling system to the cooling pond and from the cooling pond to the Illinois River. Section 4.9.1 concluded that impacts from microbiological agents resulting from the presence of elevated water temperatures would be SMALL because (1) the area of the thermal discharge mixing zone is small compared to the size of the river in the discharge area, (2) the duration for which heated effluent is allowed to exceed critical temperatures is limited, (3)activities that could result in immersion of a person in the cooling pond are prohibited, and (4)the Illinois Department of Public Health has stated (as of June 2013) that there has never been a case of *Naegleria* infection reported in Illinois (IDPH 2013b). Therefore, Exelon Generation concludes that LSCS's contribution to any cumulative adverse impacts from exposure to microbiological organisms would be SMALL.

NRC (NRC 2013b) concluded that the non-radiological health impacts from chronic exposure to electromagnetic fields cannot be clearly linked to adverse health effects. However, acute effects of electric shock from induced current under transmission lines could potentially be cumulative. Because there are no in-scope transmission lines at LSCS, license renewal would not contribute to cumulative induced current impacts.

Exelon Generation concludes that LSCS's contribution to cumulative impacts on human health from all non-radioactive sources would be SMALL.

4.12.4.2 Radiological Health Impacts

Radiological dose limits for protection of the public and workers have been developed by EPA and NRC to ensure that the cumulative impacts of acute and long-term exposure to radiation and radioactive material are SMALL regardless of the source or sources. Operation of LSCS during the license renewal term will comply with these dose limits, which are codified in 10 CFR Part 20 and 40 CFR Part 190.

Therefore, Exelon Generation concludes that LSCS's contribution during the license renewal term to cumulative dose received by workers and the public from all sources, and thus to radiological health impacts, would be SMALL.

4.12.5 Socioeconomics

Sections 2.5 on employment at LSCS, 3.9 on socioeconomic conditions of LaSalle County, and 3.11 on minority and low-income populations within an 80-km (50-mi) radius of the plant give background information pertinent to cumulative socioeconomic impacts. Site-specific socioeconomic impacts were not evaluated for LaSalle in this environmental report because the NRC has already generically concluded (NRC 2013b) that potentially adverse socioeconomic impacts from the continued operation of any nuclear plant would be SMALL and not require plant-specific analyses. LSCS's impacts to minority and low-income populations were evaluated in Section 4.10.

Continued operation of LSCS during the license renewal term would have no impact on socioeconomic conditions in the region beyond those already experienced. Because Exelon Generation has no plans to significantly alter the number of workers during the license renewal term, overall expenditures and employment levels at the Station would remain relatively constant and would not increase the demand for permanent housing or public services. Therefore, changes to population or tax-related land use impacts from LSCS are not expected. The LaSalle County draft Comprehensive Plan identified no future development plans that would affect land use, housing, taxes, education or public services. There would be no disproportionately high and adverse health or environmental impacts from LSCS to minority or low-income populations in the region. Hence, Exelon Generation concludes that LSCS's contribution to changes in the cumulative socioeconomic conditions in the region would be SMALL during the license renewal term.

4.13 Impacts Common to All Alternatives: Uranium Fuel Cycle

Non-radiological impacts of the uranium fuel cycle, which the GEIS (NRC 2013b) designates as a Category 1 issue, were reviewed for new and significant information that could make the generic finding for a resource as described in the 2013 GEIS inapplicable at LSCS. No new and significant information was identified. Therefore, Exelon Generation adopts the non-radiological impacts of the uranium fuel cycle on environmental resources that are described in the GEIS, and no further analysis is needed for LSCS.

The final spent fuel continued storage rule and Generic EIS for Continued Storage of Spent Nuclear Fuel (79 *Federal Register* 56238, 56250 (September 19, 2014)) update the 2013 GEIS evaluation of the effects of onsite storage of spent fuel during the term of an extended license (resulting from the renewal of the plant's operating license). The updated evaluation concludes that impacts, including radiological impacts, of onsite storage of spent fuel during the term of an extended license would be SMALL. Exelon Generation is aware of no new and significant information that could make the generic finding regarding radiological impacts of onsite storage of spent fuel during the term of an extended license invalid for LSCS. Therefore, Exelon Generation adopts the conclusion described in the Generic EIS for Continued Storage of Spent Nuclear Fuel for this Category 1 issue (NRC 2013b), and no further analysis is needed for LSCS.

The final spent fuel continued storage rule and Generic EIS for Continued Storage of Spent Nuclear Fuel also update the evaluation in the 2013 GEIS regarding the radiological impacts to the environment from the offsite disposal of spent nuclear fuel and high-level waste and reclassify the issue from an uncategorized issue to a Category 1 issue (79 *Federal Register* 56238, 56263 (September 19, 2014)). The updated evaluation concludes that radiological impacts of offsite disposal of spent nuclear fuel and high-level waste would not be sufficiently large to require elimination of the option of extended operation under 10 CFR Part 54. Exelon Generation is aware of no new and significant information that could make the generic finding regarding radiological impacts of offsite disposal of spent nuclear fuel and high-level waste invalid for LSCS-generated spent nuclear fuel. Therefore, Exelon Generation adopts the conclusion described in the Generic EIS for Continued Storage of Spent Nuclear Fuel for this Category 1 issue, and no further analysis is needed for LSCS.

Information regarding the impacts of transporting spent nuclear fuel, which is a Category 1 issue, was also reviewed. Some information for LSCS was found to be new but is not significant for the reasons explained below.

NRC has standardized the analysis of impacts for transporting radioactive materials to and from nuclear reactors in Table S-4 of 10 CFR 51.52. Table S-4 provides the impacts for transport of fresh fuel to and spent fuel from a reference 1,100-MWe reactor operating at 80 percent capacity factor under normal and accident conditions. The 2013 GEIS (NRC 2013b) concluded that such impacts would be SMALL for fresh fuel enriched up to 5 percent uranium-235 and for spent fuel with an average burnup for the peak rod of up to 62,000 MWd/MTU (megawatt-days per metric ton uranium). Also, the cumulative impacts of transporting spent fuel to a single repository, such as Yucca Mountain, Nevada were found to be consistent with the impact values contained in Table S-4. Accordingly, the GEIS concluded that transportation of radiological materials was a Category 1 issue with SMALL impacts, regardless of the nuclear plant being considered.

As Section 2.2.2 indicates, both LSCS units are licensed for low-enriched, uranium dioxide fuel with enrichment not exceeding a nominal 5.0 percent by weight of uranium-235. However, the average peak rod fuel burn-up for both LSCS units is projected to exceed 62,000 MWd/MTU in some rods in some fuel cycles. Accordingly, Exelon Generation has assessed the implications for the environmental impact values reported in Table S-4 of 10 CFR 51.52. Results of the assessment are summarized below.

Spent Fuel Characteristics

Both LSCS units have fuel in the core that includes part-length rods. The fuel includes the Global Nuclear Fuel (GNF) 2 and AREVA ATRIUM-10 nuclear fuel assemblies. (Weggeman 2014; BWR 2008)

- The GNF2 design is a 10×10 array with 92 fuel rods and two large central water rods, eight long part-length rods and six short part-length rods. (Exelon Generation 2013d).
- The ATRIUM-10 design is a 10×10 array with 83 full-length fuel rods, 8 part-length fuel rods, and one centrally located water channel (Exelon Nuclear 2012a).

The part-length fuel rods are attached to the fuel bundle lower tie plate and typically experience higher burnups and higher power than full-length rods due to the bottom-peaked axial power shapes that exist throughout a large portion of a BWR fuel cycle. Average peak rod burnup for some LSCS Unit 1 part-length rods has been estimated to reach approximately 63,600 MWd/MTU in a near-term fuel cycle. Average peak rod burnup for full-length rods is not expected to exceed 62,000 MWd/MTU.

Methodology

Exelon Generation evaluated the radiological effects of transporting either GNF2 or ATRIUM-10 spent fuel assemblies with high burnup. The ORIGEN code was used to estimate radionuclide inventories for the fuel. A representative high-burnup case was identified for the GNF2 fuel at a burnup level of 75,000 MWd/MTU and enrichment of 5.0 percent by weight of uranium-235. The radionuclide inventory for this case was used in the RADTRAN analysis to estimate the radiological impacts of transportation of high-burnup spent fuel to a repository for disposal. For purposes of analysis, the destination for the shipments was assumed to be Yucca Mountain Nevada. Exelon Generation assumed that all spent fuel shipments would be made using legal weight trucks. Fuel shipments were assumed to take place 5 years after discharge from the reactor. The average annual quantity of spent fuel shipped is assumed to equal the average annual reload quantity (approximately 160 fuel assemblies per reactor for a 24-month refueling cycle).

Environmental Impacts of Transportation

Incident-free Transportation

This evaluation considered whether the environmental effects of normal (incident-free) spent fuel shipments are within the bounds established by Table S-4 in 10 CFR 51.52. The bounding cumulative doses to the exposed population are:

Transportation workers	4 person-rem/reactor-year
General public (onlookers)[4]	3 person-rem/reactor-year
General public (along route)[5]	3 person-rem/reactor year

The RADTRAN analysis provides the normal dose as person-rem per shipment. These doses were converted to person-rem per reactor-year of operation. Burnup was a factor in determining the maximum number of assemblies that a transportation cask could hold; however, the per-shipment results are independent of burnup because the external radiation dose rate emitted from the cask was set to the regulatory limit and is independent of the actual cask contents. The characteristics of the LSCS reactors (annualized number of fuel assemblies discharged, combined electrical output of 2,327 MW(e), capacity factor of 92 percent) were used to normalize the results to a reference reactor year for comparison to Table S-4.

The population dose estimates for LSCS spent fuel shipments are summarized below.

Population dose (person-rem per shipment)		
Transportation workers	General public (onlookers)	General public (along route)
0.0377	0.291	0.0378
Population dose (person-rem per reactor year)		
Transportation workers	General public (onlookers)	General public (along route)
0.189	1.46	0.189

The doses associated with incident-free transportation of spent fuel with burnup to 75,000 MWD/MTU are bounded by the doses given in 10 CFR 51.52, Table S-4, if dose rates from the shipping casks are maintained within regulatory limits.

Accidents during Transportation

Exelon Generation evaluated the environmental effects of accidents during spent fuel transport. Accident risks are the multiplicative product of the likelihood of an accident involving a spent-fuel shipment and the consequences of a release of radioactive material resulting from the accident. The consequences of such a transportation accident are represented by the population dose risk from a release of radioactive material, assuming that an accident occurs that results in the breach of a shipping cask's containment systems. The consequences are a

[4] Persons at stops and sharing the highway
[5] Persons living near the highway (within 800-meter buffer on each side)

function of the total amount of radioactive material in the shipment, the fraction that escapes from a shipping cask, the existence of a pathway that introduces radioactive material to humans, and the characteristics of the exposed population.

Exelon Generation used the RADTRAN code to estimate impacts of transportation accidents involving spent fuel shipments. In the RADTRAN analysis, increasing burnup affects both the likelihood of transportation accidents and the potential consequences of a release. The likelihood of an accident is directly proportional to the number of spent fuel shipments. As noted above, the number of assemblies in a cask is reduced as the fuel burnup increases, to keep the activity of key radionuclides in the cask relatively constant. However, the number of shipments per reactor year remains relatively constant with increased burnup because increased burnup reduces the number of assemblies removed from the reactor core on an annualized basis.

Assuming shipments containing five spent fuel assemblies at the peak rod burnup, the postulated accident risks associated with transportation of spent fuel are provided below.

Population dose-risk (person-rem per shipment)[6]	Population dose-risk (person-rem per reference reactor year)
3.53×10^{-6}	9.3×10^{-5}

Table S-4 characterizes the radiological effects of transportation accidents as SMALL. The accident collective dose-risk consequences from shipments of spent fuel from LaSalle are very small. For comparison, the U.S. average background radiation is approximately 620 mrem per year, with roughly half of the dose (310 mrem per year) coming from natural radiation exposure and the other half from man-made sources (NRC 2014). The total population within the 800-meter buffer zone along the transport route is 347,991 people. Thus, the population along the transport route receives an average collective dose-risk of approximately 108,000 person-rem per year from exposure to natural sources of radiation. Given that the probability of occurrence of this dose is one, the dose-risk is also 108,000 person-rem per year. Comparing the average annual collective dose-risk to the probability-weighted collective dose-risk from the annualized spent fuel shipments shows that the contribution of fuel shipments from LaSalle to the total population collective dose is extremely small. Therefore, no detectable increase in environmental risk effects is expected as a result of accidents that may result from shipments of higher burnup spent fuel from LSCS to a repository.

Conclusion

Based on the analyses above, Exelon Generation concludes that radiological impacts of transporting LSCS's spent nuclear fuel would be bounded by the doses given in 10 CFR 51.52, Table S-4, and hence, would be SMALL. Accordingly, while the expectation that average peak rod burnup in some part-length fuel rods at LSCS will exceed 62,000 MWd/MTU is new information, it is not significant because the impacts of transporting LSCS spent fuel are within the bounds of those predicted in the 2013 GEIS (NRC 2013b) for all plants and the analysis presented here did not suggest radiological impacts different from the transportation of spent fuel for any other plant. Therefore, no further mitigation would be required based on this new information for the environmental impact values associated with transporting radioactive materials to and from nuclear reactors as reported in Table S-4 of 10 CFR 51.52.

[6] The value presented is the product of probability times collective dose.

4.14 Termination of Nuclear Power Plant Operations and Decommissioning

The termination of nuclear power plant operations and decommissioning are Category 1 issues that were reviewed for new and significant information at LSCS that could make the generic finding for a resource as described in the GEIS inapplicable.

No new and significant information was identified, therefore the conclusions regarding impacts from the termination of nuclear power plant operations and decommissioning on environmental resources described in the GEIS are considered appropriate for the LSCS license renewal and do not need further analysis.

4.15 Severe Accident Mitigation Alternatives Analysis

NRC

> **The environmental report must contain a consideration of alternatives to mitigate severe accidents "…if the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environment assessment..." 10 CFR 51.53(c)(3)(ii)(L)**
>
> **"…The probability weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to groundwater, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives…." 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 66**

Section 4.15 summarizes an analysis of alternative ways to mitigate the impacts of severe accidents at LSCS. Appendix F provides a detailed description of the severe accident mitigation alternatives (SAMA) analysis.

NRC defines "design basis" accidents as postulated accidents during which, should they occur, NRC requires the plant design and construction to be robust enough to ensure that the plant can withstand normal and abnormal transients (e.g., rapid changes in reactor power) without undue risk to the health and safety of the public. "Severe accidents" (i.e., beyond design basis) are defined as postulated accidents that could result in substantial damage to the reactor core, whether or not there are serious off-site consequences (NRC 2013b).

In the 2013 GEIS, NRC reexamined the information from its 1996 GEIS and concluded that the unmitigated environmental impacts from severe accidents still meet Category 1 criteria, and that consideration of severe accident mitigation alternatives remains a Category 2 issue (NRC 2013b). Site-specific information to be presented in the license renewal environmental report includes: (1) potential SAMAs; (2) benefits, costs, and net value of implementing potential SAMAs; and (3) sensitivity of analysis to changes in key underlying assumptions.

Exelon Generation maintains a probabilistic risk assessment (PRA) model to evaluate the most significant risks of radiological release from LSCS fuel into the reactor and from the reactor into the containment structure. The original LSCS IPE/IPEEE was submitted to the NRC in 1994 (ComEd 1994a) with a subsequent correction being docketed later in the same year (ComEd 1994b). In order to maintain fidelity with the operating plant, to reflect the latest PRA technology, and to support application specific efforts, the PRA model was updated numerous times between 1994 and 2014. The most recent update was performed to upgrade the Large Early Release Frequency (LERF) model to a full Level 2 model to support the SAMA analysis.

For the SAMA analysis, Exelon Generation used the LSCS PRA model output as input to an NRC-approved consequence assessment code that calculates economic costs and dose to the public from hypothesized releases from the containment to the environment. This Level 3 PRA model uses the MELCOR Accident Consequences Code System Version 2 (MACCS2). MACCS2 requires certain site specific information, such as agricultural-based economic data, population estimates, and meteorological data, which are described in more detail in

Appendix F. These inputs were developed using data in the 2007 National Census of Agriculture (USDA 2009) and from the Bureau of Economic Analysis (BEA 2013) for each of the 21 counties surrounding the plant, to a distance of 50 miles. Then, using the NRC regulatory analysis techniques documented in NUREG/BR-0184 (NRC 1997), Exelon Generation calculated the monetary value of the unmitigated LSCS severe accident risk. The result represents the monetary value of the baseline risk of dose to the public and workers, offsite and onsite economic costs, and replacement power cost. This value was used as a cost/benefit-screening tool for potential SAMAs; a SAMA whose cost of implementation exceeded the baseline cost-risk value was rejected as being not cost-beneficial for LSCS.

LSCS Units 1 and 2 are essentially identical in design and operation. Such differences that do exist are not believed to be significant from a risk perspective. Hence, the PRA model[7] results employed to estimate the baseline cost-risk and the averted cost risk for each un-screened Unit 2 SAMA were assumed to be representative of the results that would be obtained from a Unit 1 PRA model. That is, if a particular SAMA proved cost beneficial for Unit 2, it was assumed to also be cost beneficial for Unit 1.

Exelon Generation used industry, NRC, and LSCS-specific information to create a list of 27 SAMAs for consideration. Exelon Generation analyzed this list to screen out any SAMAs that (1) had already been implemented at LSCS, or (2) would achieve results that Exelon Generation had already achieved at LSCS by other means. Three SAMAs were screened out based on these criteria. Therefore, Exelon Generation prepared cost estimates for implementing each of the remaining 24 SAMAs and used the baseline cost-risk value to screen out SAMAs that would not be cost-beneficial to implement.

For each of the un-screened SAMAs, Exelon Generation calculated the cost-risk value for the plant configuration in which the SAMA would be implemented. The difference between the baseline cost-risk value and the cost-risk value of the plant configuration in which the SAMA was implemented was defined as the “averted cost-risk”. The averted cost-risk represents the monetary the value of the risk reduction (the benefit) associated with implementing the SAMA. Exelon Generation then compared the benefit of each un-screened SAMA to its cost of implementation; SAMAs with benefits that exceeded their implementation costs were defined as “potentially cost-beneficial”.

Exelon Generation performed additional sensitivity analyses to evaluate how the SAMA analysis would change if certain key parameters were changed. The results of the sensitivity analyses are discussed in Appendix F.

Based on the results of this SAMA analysis, Exelon Generation identified 15 SAMAs for LSCS that have the potential to reduce plant risk and be cost-beneficial at the 95th percentile. None are related to managing the effects of plant aging during the period of extended operation. The potentially cost beneficial SAMAs will be submitted to the LSCS Plant Health Committee, which will consider them for implementation in accordance with an established plant procedural process.

[7] The LSCS PRA model is a Unit 2-only model; there is no logic in the PRA that can be used to quantify a Unit 1 CDF or release category frequencies.

Chapter 5

Assessment of New and Significant Information

LaSalle County Station Environmental Report

5.1 Discussion

NRC

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

The NRC licenses operation of domestic nuclear power plants and provides for license renewal, requiring a license renewal application that includes an environmental report (10 CFR 54.23). NRC regulations, 10 CFR Part 51, prescribe the environmental report content and identify the specific analyses the applicant must perform. In an effort to streamline the environmental review, NRC has resolved most of the environmental issues generically (Category 1 issues) and requires an applicant's analysis of only the remaining site-specific issues (Category 2 issues).

While NRC regulations do not require an applicant's environmental report to contain analyses of the impacts of those Category 1 environmental issues that have been generically resolved [10 CFR 51.53(c)(3)(i)], the regulations do require that an applicant identify any new and significant information of which the applicant is aware that relates to those issues [10 CFR 51.53(c)(3)(iv)]. The purpose of this requirement is to alert NRC staff to such information, so the staff can determine whether to seek the Commission's approval to waive or suspend application of the rule with respect to the affected generic analysis. NRC has explicitly indicated, however, that an applicant is not required to perform a site-specific validation of GEIS conclusions unless the applicant is aware of new and significant information that would change the conclusions in the GEIS (NRC 2013b).

Exelon Generation expects that new and significant information would include:

- Information that identifies a significant environmental issue not covered in the GEIS and consequently not codified in the regulation, or
- Information or circumstances at a site that were not considered in the GEIS analyses and that lead to an impact finding that presents a seriously different picture of the environmental impact of the proposed project in comparison with what was envisioned in the GEIS.

NRC has not provided specific criteria for evaluating whether new information or circumstances present a seriously different picture of environmental impacts than were generically resolved to be Category 1 issues, thus making them "significant." Therefore, for the purpose of its review, Exelon Generation used guidance available in Council on Environmental Quality (CEQ) regulations. The National Environmental Policy Act authorizes CEQ to establish implementing regulations for federal agency use. NRC requires license renewal applicants to provide NRC with input, in the form of an environmental report, that NRC will use to meet National Environmental Policy Act requirements as they apply to license renewal (10 CFR 51.10).

CEQ guidance provides that federal agencies should prepare environmental impact statements for actions that would significantly affect the environment (40 CFR 1502.3), focus on significant environmental issues (40 CFR 1502.1), and eliminate from detailed study issues that are not significant [40 CFR 1501.7(a)(3)]. The CEQ guidance includes a lengthy definition of "significantly" that requires consideration of the context of the action and the intensity or severity of the impact(s) (40 CFR 1508.27). Exelon Generation considered that MODERATE or LARGE impacts, as defined by NRC, would be seriously different than previously envisioned impacts.

Therefore, only new information that would suggest a change from SMALL impacts to either MODERATE or LARGE impacts for an issue considered in the GEIS or an issue not considered in the GEIS with MODERATE or LARGE impacts would be considered "significant." Chapter 4 presents the NRC definitions of SMALL, MODERATE, and LARGE impacts.

As part of the preparation of this license renewal application Exelon Generation reviewed all the Category 1 issues that apply to LSCS for new and significant information. The assessment included: (1) interviews with Exelon Generation subject matter experts on the validity of the conclusions in the GEIS as they relate to LSCS, (2) an extensive review of documents related to environmental issues at LSCS, the Illinois River, and the cooling pond, (3) correspondence with state and federal agencies to determine if the agencies had concerns relevant to their resource areas that had not been addressed in the GEIS, (4) credit for Exelon Generation environmental monitoring and reporting required by regulations and oversight of Station facilities and operations by state and federal regulatory agencies (permanent activities that would bring significant issues to Exelon Generation's attention), and (5) review of previous license renewal applications for issues relevant to the LSCS application.

As described in Section 5.2, Exelon Generation identified one Category 1 issue in which LSCS-specific information was not considered in the GEIS evaluation (NRC 2013b), and therefore, is new information: the peak fuel burnup at LSCS is projected to exceed 62,000 MWd/MTU in some part-length fuel rods during some fuel cycles, which exceeds the upper limit of fuel burnup considered in the GEIS (NRC 2013b). Therefore, Exelon Generation conducted a review of the impact of this new information on the fuel transportation conclusions in the GEIS (NRC 2013b) to determine if the information was also significant; that is, that it would change the conclusion of the NRC (NRC 2013b) regarding the impacts of the transportation of used fuel.

5.2 Uranium Fuel Cycle – Transportation

In 1999, the NRC issued an addendum to the 1996 GEIS (NRC 1999b) in which the agency concluded that the values given in 10 CFR 51.52, Table S-4 would bound the environmental impacts of transporting spent fuel and waste to and from one nuclear power plant, as long as (1) enrichment of the fresh fuel was 5 percent or less, (2) burn-up of the spent fuel was 62,000 MWd/MTU or less, and (3) spent fuel was cooled for at least 5 years before being shipped offsite. In the 2013 GEIS (NRC 2013b), the NRC noted that a later study found that the impacts presented in Table S-4 would also bound the potential environmental impacts that would be associated with transportation of spent nuclear fuel with up to 75,000 MWd/MTU burnup, provided that the fuel is cooled for at least 5 years before shipment (NRC 2013b).

As noted in Section 2.2.2, the peak fuel burnup at LSCS is projected to exceed 62,000 MWd/MTU in some part-length fuel rods during some fuel cycles. Accordingly, Exelon Generation assessed the potential impacts of the fuel burnup of partial-length rods exceeding 62,000 MWd/MTU and compared the results with the environmental impact values reported in 10 CFR 51.52, Table S-4. Based on this analysis, which is described in Section 4.13 of this environmental report, Exelon Generation concludes that, while this information for LSCS is new, it is not significant because impacts from transporting LSCS spent fuel with higher burnup would be bounded by the values presented in 10 CFR 51.52, Table S-4, and hence would be SMALL. Therefore, future transportation of LaSalle-generated spent fuel with burnup exceeding 62,000 MWd/MTU does not present a different picture of environmental impacts from the spent fuel transportation circumstances generically resolved in the 2013 GEIS to be a Category 1 issue.

5.3 Conclusion

In its entirety, Exelon Generation's assessment did not identify any new and significant information regarding the LSCS environment or operations that would (1) make any generic conclusion codified by the NRC for Category 1 issues not applicable to LSCS, (2) alter regulatory or GEIS statements regarding Category 2 issues, or (3) suggest any other measure of license renewal environmental impact not considered in the GEIS.

Chapter 6

Summary of License Renewal Impacts and Mitigating Actions

6.1 License Renewal Impacts

Exelon Generation has reviewed the environmental impacts of renewing the LSCS operating licenses and has concluded that all impacts would be SMALL and would not require mitigation. This Environmental Report documents the basis for Exelon Generation's conclusions. Chapter 4 incorporates by reference the NRC's findings for the 50 license renewal Category 1 issues identified in Appendix B to Subpart A of 10 CFR Part 51, Table B-1 that apply to LaSalle (Appendix A, Table A-1), all of which have impacts that are SMALL. Chapter 4 also presents LSCS site-specific analyses of the Category 2 issues identified in Appendix B to Subpart A of 10 CFR Part 51, Table B-1, and concludes that such issues are either not applicable or have SMALL impacts.

Table 6.1-1 identifies the impacts that LSCS's license renewal would have on resources associated with the Category 2 issues.

Table 6.1-1 Environmental Impacts Related to License Renewal at LSCS

GEIS Issue No.	Category 2 Issue	Environmental Impact
	Surface Water Resources	
17	Surface water use conflicts (plants with cooling ponds or cooling towers using makeup water from a river)	**SMALL.** The average consumptive use of Illinois River water is less than 0.5 percent of the 92-year annual average mean flow at Marseilles Pool. The maximum withdrawal capacity is approximately 1.8 percent of the river's 92-year annual average mean flow at Marseilles Pool. Withdrawal during low-flow periods are restricted by the LSCS Extreme Heat Implementation Plan and the Station's water withdrawals will not increase during the license renewal term.
	Groundwater Resources	
22	Groundwater use conflicts (plants that withdraw > 100 gpm)	**NONE.** The issue does not apply because LSCS withdrew an annual average of 26.1 gpm of groundwater for water years 2008 through 2012.
23	Groundwater use conflicts (plants with closed-cycle cooling systems that withdraw makeup water from a river)	**SMALL.** The maximum net consumptive loss from the river would be 1.5 percent of the river's 92-year annual average mean flow. The average net consumptive loss represents less than 0.5 percent of the river's 92-year annual average mean flow. The site's groundwater wells pump an average of 26.1 gpm from an aquifer that is not hydrologically connected to the alluvial aquifer. Water withdrawals and consumptive use will not increase during the license renewal term.
26	Groundwater quality degradation (plants with cooling ponds at inland sites)	**SMALL.** Seepage from the cooling pond is negligible because of the characteristics of the underlying material: the cooling pond is separated from the Cambrian-Ordovician Aquifer by more than 100 m (330 ft) of predominantly clay sediments, which effectively seal the deep (drinking water) aquifer from any cooling pond seepage. Tritium is not present in the cooling pond in concentrations above 200 pCi/L. LSCS has a Radiological Groundwater Protection Program that monitors groundwater and provides for remediation of radiological spills to groundwater or soils. LSCS has plans and procedures that address the minimization of spills of various non-radioactive materials.

Table 6.1-1 Environmental Impacts Related to License Renewal at LSCS (Continued)

GEIS Issue No.	Category 2 Issue	Environmental Impact
	Terrestrial Resources	
27	Radionuclides released to groundwater	**SMALL.** Seepage from the cooling pond is negligible because of the characteristics of the underlying material: the cooling pond is separated from the Cambrian-Ordovician Aquifer by more than 100 m (330 ft) of predominantly clay sediments, which effectively seal the deep (drinking water) aquifer from any cooling pond seepage. The shallow aquifer is not used for drinking water. Radionuclides are not migrating offsite. LSCS has a Groundwater Protection Program that monitors groundwater and provides for remediation of radiological spills to groundwater or soils.
28	Effects on terrestrial resources (non-cooling system impacts)	**SMALL.** Terrestrial communities at LSCS consist of species that can tolerate relatively high levels of human activity and industrial activity-generated noise, and the current community composition has adjusted to operations and maintenance activities over the current license term. Operations and maintenance activities during the license renewal term are expected to be similar to current activities.
33	Water use conflicts with terrestrial resources (plants with cooling ponds or cooling towers using makeup water from a river)	**SMALL.** The average consumptive use of Illinois River water (less than 0.5 percent of the 92-year annual average mean flow at Marseilles Pool) would not limit the availability of water in the alluvial aquifer or to riparian communities. Withdrawals during low-flow periods are restricted by LSCS procedures. LSCS's limited use of groundwater from the deep Cambrian-Ordovician Aquifer would have no effect on the alluvial aquifer and there are no wildlife or plant species in the vicinity of LSCS that are restricted to or dependent upon riparian communities.
	Aquatic Resources	
36	Impingement and entrainment of aquatic organisms (plants with once-through cooling systems or cooling ponds)	**SMALL.** LSCS's NPDES permit constitutes the current Clean Water Act Section 316(b) determination that the cooling water intake structure represents Best Technology Available as evidenced by the closed-cycle cooling system which requires only small amounts of water for cooling pond makeup, and typically has an intake velocity of 0.2 m/second (0.5 ft/second). Almost 30 years of fishery monitoring in the Marseilles Pool indicates no plant-related impacts.

Table 6.1-1 Environmental Impacts Related to License Renewal at LSCS (Continued)

GEIS Issue No.	Category 2 Issue	Environmental Impact
39	Thermal impacts on aquatic organisms (plants with once-through cooling systems or cooling ponds)	**SMALL.** LSCS's closed-cycle cooling system blowdown discharge meets state water quality (thermal) standards, affects a very small area of the Illinois River, and does not block fish passage.
46	Water use conflicts with aquatic resources (plants with cooling ponds or cooling towers using makeup water from a river)	**SMALL.** The average consumptive use of Illinois River water (less than 0.5 percent of the 92-year annual average mean flow at Marseilles Pool) would not limit the availability of water in the alluvial aquifer or to riparian communities. Withdrawals during low-flow periods are managed in accordance with LSCS procedures.
	Special Status Species and Habitats	
50	Threatened, endangered, and protected species and Essential Fish Habitat	**NOT LIKELY TO ADVERSELY AFFECT.** No federally-listed species are known to occur in the vicinity of LSCS, no critical habitats occur in the vicinity of LSCS, no changes in operations are expected over the license renewal term, no major construction or refurbishment is planned, and resources agencies expressed no concerns regarding the effect of license renewal on threatened or endangered species (Appendix D). Illinois has no Essential Fish Habitat, which is limited to marine environments.
	Historic and Cultural Resources	
51	Historic and cultural resources	**HISTORIC PROPERTIES ARE PRESENT, BUT NOT ADVERSELY AFFECTED.** Operation and maintenance at LSCS have not resulted in any adverse impacts to recorded archaeological sites; Exelon Generation has procedures in place to protect undiscovered cultural resources; and the Illinois SHPO voiced no concerns about the continued operation of **LSCS** (Appendix E).
	Human Health	
60	Microbiological hazards to the public (plants with cooling ponds or canals or cooling towers that discharge to a river)	**SMALL.** The area of the thermal discharge mixing zone is small compared to the size of the river in the discharge area; the duration for which heated effluent to the river is allowed to exceed critical temperatures is limited; activities that could result in immersion of a person in the cooling pond, such as swimming and water skiing, are prohibited; and the Illinois Department of Public Health has stated (as of June 2013) that there has never been a case of Naegleria infection reported in Illinois.
64	Electric shock hazards	**SMALL.** Electric shock hazards are controlled on the LSCS site in accordance with applicable industrial safety procedures. LSCS has no in-scope transmission lines as defined by footnote 4 of Table B-1 of 10 CFR Part 51.

Table 6.1-1 Environmental Impacts Related to License Renewal at LSCS (Continued)

GEIS Issue No.	Category 2 Issue	Environmental Impact
	Postulated Accidents	
66	Severe accidents	**SMALL**. Exelon Generation identified 15 SAMAs with the potential to reduce plant risk and be cost-beneficial at the 95th confidence percentile. None are related to managing the effects of aging during the period of extended operations. All will be submitted to the LSCS Plant Health Committee for review and evaluation, in accordance with an established procedure.
	Environmental Justice	
67	Minority and low-income populations	**SMALL**. The impacts of the extended operation of LSCS have been determined in this environmental report to be SMALL for all issues. The locations of minority and low-income populations within an 80-km (50-mi) radius of LSCS are not expected to be disproportionally affected by any activities described in Chapter 4. No subsistence-like populations live in the area.
	Cumulative Impacts	
73	Cumulative impacts	**SMALL**. Future LSCS operations will be similar to past operations. Evaluations in Chapter 4 of this environmental report of past impacts to the Illinois River, groundwater, air, threatened or endangered species, critical habitats, Essential Fish Habitats, cultural resources, socioeconomics, and radiological doses conclude that future impacts from LSCS would be SMALL. Releases of pollutants to air are limited by permit. Thermal releases to the Illinois River are limited by permit. Exelon has procedures that limit water withdrawal from the Illinois River during periods of low flow. Radiological doses are limited by regulation. Threatened and endangered species and cultural resources are protected by state and federal regulations. Changes to population or tax-related land use impacts from LSCS are not expected because Exelon Generation has no plans to hire additional workers during the license renewal term.

6.2 Mitigation

NRC

> **"The report must contain a consideration of alternatives for reducing adverse impacts… for all Category 2 license renewal issues…" 10 CFR 51.53(c)(3)(iii)**
>
> **"The environmental report must include an analysis that considers and balances… alternatives available for reducing or avoiding adverse environmental effects…" 10 CFR 51.45(c) as incorporated by 10 CFR 51.53(c)(2) and 10 CFR 51.45(c)**

Chapter 4 in this Environmental Report concludes that impacts of LSCS license renewal activities would be SMALL for all Category 2 issues to which the NRC applies the levels SMALL, MODERATE or LARGE as a measure of significance. Threatened or endangered species are determined "not likely to be adversely affected" by license renewal activities. Cultural resources are determined to be "not likely adversely affected." Also, Chapter 4 adopts by reference the findings of the 2013 GEIS of SMALL impacts for applicable Category 1 issues.

Current operations include monitoring activities that would continue during the license renewal term. Exelon Generation performs routine monitoring to ensure the safety of workers, the public, and the environment. These activities include gaseous and liquid radiological release monitoring and environmental monitoring in accordance with the LSCS operating license technical specifications issued by the NRC, groundwater monitoring in accordance with the LSCS Radiological Groundwater Protection Program (RGPP), and effluent monitoring in accordance with the NPDES permit issued by the Illinois EPA. These programs ensure that the Station's emissions and effluents are within regulatory limits, and that unusual or off-normal emissions are quickly detected, thus mitigating potential impacts.

Tritium from historic releases is present in shallow groundwater beneath LSCS. Since 2006, Exelon Generation has been preparing and submitting to the NRC annual reports summarizing the status of the LSCS RGPP. Remediation activities include installation of monitoring wells, increased groundwater sampling frequency, natural monitored attenuation, and the installation of an extraction well to control the migration of the tritium plume. To date, no tritium has migrated offsite, and tritium migration offsite is not expected. Hydrogeological investigations indicate there is no feasible pathway into a drinking water supply. Tritium investigations and remediation activities are discussed in Section 3.6.6.2.

As Section 2.2.3 in this Environmental Report discusses, potential environmental effects from both makeup and blowdown pipe breaks may occur, including localized flooding and erosion in the vicinity of the breaks, and possibly, minor releases of radioactivity from blowdown line breaks. Accordingly, actions are being implemented to reduce the frequency of breaks and to reduce impacts when breaks occur. Examples of such mitigative measures include installation over time of pipeline relief valves that allow controlled venting, changing operational setpoints to reduce the probability of makeup water pump trips, keeping certain pipeline replacement parts on hand, implementing a plan for rapid pipeline repairs, backfilling as necessary of eroded areas, and implementing conservative controls for operation of blowdown valves and makeup water pumps.

This Environmental Report identified no additional mitigation measures beyond those described here that are sufficiently beneficial to be warranted.

6.3 Unavoidable Adverse Impacts

NRC

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

This Environmental Report adopts by reference the NRC findings for applicable Category 1 issues, including discussions of any unavoidable adverse impacts (Appendix A, Table A-1). Exelon Generation examined the 17 Category 2 issues identified in the GEIS to assess site-specific impacts. Exelon identified the following unavoidable adverse impacts of license renewal activities:

- Solid radioactive wastes are a product of plant operations and permanent disposal is necessary.
- Disposal of nonradioactive and radioactive wastes will result in a small impact as long as the plant is in operation. Disposal procedures for these wastes are intended to reduce adverse impacts to acceptably low levels.
- Operation of LSCS results in a very small increase in radioactivity in air and water. Based on data collected since initial operation, the increase is less than the fluctuation in natural background levels and is expected to remain so over the license renewal term. Operation of LSCS also creates a very low probability of accidental radiation exposure to LSCS employees and inhabitants of the area.
- Operation of LSCS results in consumptive use of groundwater and surface water.
- Loss of small numbers of adult and juvenile fish impinged on traveling screens.
- Loss of small numbers of larval fish and shellfish entrained at the intake structures.

6.4 Irreversible and Irretrievable Resource Commitments

NRC

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

Continued operation of LSCS for the license renewal term will result in irreversible and irretrievable resource commitments, including the following:

- Nuclear fuel, which is used in the reactor and is converted to radioactive waste;
- Land required to permanently disposition offsite the following: spent nuclear fuel, low-level radioactive wastes generated as a result of plant operations, and nonradioactive industrial wastes generated from normal industrial operations;
- Elemental materials that will become radioactive; and
- Materials used for the normal industrial operations of LSCS that cannot be recovered or recycled or that are consumed or reduced to unrecoverable forms.

6.5 Short-Term Use Versus Long-Term Productivity of the Environment

NRC

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

The current balance between short-term use and long-term productivity at LSCS was established with the decision to convert approximately 1,568 ha (3,875 ac) to energy production. The Final Environmental Statement related to operation (NRC 1978) evaluated the impacts of operating LSCS. Natural resources that would be subjected to short-term use include land and water. Land in the immediate vicinity of LSCS is largely rural and agricultural.

At 100 percent load, LSCS's net consumptive loss rate of Illinois River water is less than 0.5 percent of the 92-year annual average mean flow at Marseilles. LSCS withdraws approximately 99 L/min (26.1 gpm) of groundwater from the Cambrian-Ordovician Ironton-Galesville Sandstone Aquifer.

Tritium from historic releases is present in shallow groundwater beneath LSCS. The contaminated plume does not extend offsite. Exelon Generation is performing mitigation that will avoid any long-term adverse impacts to groundwater. LSCS has a radiological groundwater protection program that includes groundwater monitoring and provides for timely identification and remediation of spills to groundwater or soils. Impacts to groundwater have been minor and would cease once reactor operations, including decommissioning, cease.

After decommissioning of the nuclear facilities at the site, most environmental disturbances would cease and restoration of the natural habitat could occur. Thus, the "trade-off" between the production of electricity and changes in the local environment is reversible to some extent. The cooling pond cannot be maintained without input from the Illinois River to replace water lost to naturally-occurring surface evaporation and seepage (although seepage is minimal, some seepage does occur). Because the cooling pond is an important recreational facility in the area and supports aquatic waterfowl, Exelon Generation and Illinois would decide its fate at the time of decommissioning.

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

Chapter 7

Alternatives to the Proposed Action

NRC

> **The environmental report shall discuss "Alternatives to the proposed action…" 10 CFR 51.45(b)(3), as adopted by reference at 10 CFR 51.53(c)(2).**
>
> **"...The report is not required to include discussion of need for power or economic costs and benefits of ... alternatives to the proposed action except insofar as such costs and benefits are either essential for a determination regarding the inclusion of an alternative in the range of alternatives considered or relevant to mitigation...." 10 CFR 51.53(c)(2).**
>
> **"…Power could be provided by a suite of alternatives and combinations of alternatives ... the number of possible combinations of alternatives that could replace the generating capacity of a nuclear power plant is potentially unlimited. Based on this, the NRC has only evaluated individual alternatives rather than combinations of alternatives…" (NRC 2013b).**
>
> **"…The consideration of alternative energy sources in individual license renewal reviews will consider those alternatives that are reasonable for the region, including power purchases from outside the applicant's service area...." (NRC 1996b)**

Chapter 7 evaluates alternatives to LSCS license renewal. The chapter identifies actions that Exelon Generation might take, and associated environmental impacts, if the NRC does not renew the LSCS operating licenses. The chapter also addresses actions that Exelon Generation has considered, but would not take, and discusses the bases for determining that such actions would be unreasonable.

In considering the level of detail and analysis that it should provide for each alternative, Exelon Generation relied on the NRC decision-making standard for license renewal: "…the NRC staff, adjudicatory officers, and Commission shall determine whether or not the adverse environmental impacts of license renewal are so great that preserving the option of license renewal for energy planning decision makers would be unreasonable" [10 CFR 51.95(c)(4)].

Exelon Generation has determined that an Environmental Report would support NRC decision-making as long as the document provides sufficient information to clearly indicate whether an alternative would have a smaller, comparable, or greater environmental impact than the proposed action. Providing additional detail or analysis serves no function if it only brings to light additional adverse impacts of alternatives to license renewal. This approach is consistent with regulations of the Council on Environmental Quality (CEQ), which provide that the consideration of alternatives (including the proposed action) should enable reviewers to evaluate their comparative merits (40 CFR Parts 1500-1508). Chapter 7 therefore provides sufficient detail about alternatives to establish the basis for necessary comparisons to the Chapter 4 discussion of impacts from the proposed action. In characterizing environmental impacts from alternatives, this section uses the same definitions of SMALL, MODERATE, and LARGE as those presented in the introduction to Chapter 4. Also the same as presented in Chapter 4 are the definitions of significance measures for (1) effects on historic and cultural resources, (2) effects on threatened and endangered species, and (3) effects on essential habitat of federally managed fish populations.

7.1 No-Action Alternative

The “no-action alternative” refers to a scenario in which the NRC does not renew the LSCS operating licenses. Unlike the proposed action, denying license renewal does not provide a means of meeting future electric system needs. Therefore, unless replacement generating capacity is provided as part of the no-action alternative, approximately 2,327 MWe of baseload generation would no longer be available, and the alternative would not satisfy the purpose and need for the proposed action. For this reason, the no-action alternative is defined as having two components—replacing the generating capacity of LSCS and decommissioning the LSCS facility, as described below.

In 2011, LSCS provided approximately 20 terawatt-hours of electricity (EIA 2013a) as baseload power to consumers in the Midwest. Replacement power could be provided by (1) building new baseload generating capacity using energy from coal, gas, nuclear, wind, solar, other sources, or some combination of these, (2) purchasing power from the wholesale market, or (3) reducing power requirements through demand side reduction. Section 7.2.1 describes each of these possibilities in detail, and Section 7.2.2 describes environmental impacts from alternatives deemed reasonable.

The NRC (NRC 2013b) defines decommissioning as the process of closing down a facility followed by reducing residual radioactivity to a level that permits the release of the property for unrestricted use or restricted use. The NRC-evaluated decommissioning options include immediate decontamination and dismantlement; safe storage of the stabilized and defueled facility for a period of time until the radioactivity decays to a level permitting unrestricted release of the property, followed by additional decontamination and dismantlement; and encasing radioactive contaminants in a structurally long-lived material, such as concrete, and maintaining the entombment structure with continued surveillance. Regardless of the option chosen, decommissioning must be completed within the 60-year period following permanent cessation of operations and permanent removal of fuel. Under the no-action alternative, Exelon Generation would continue operating LSCS until the existing licenses expire, and then initiate decommissioning activities for both units in accordance with the NRC requirements.

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

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

Exelon Generation concludes that the decommissioning impacts under the no-action alternative would not be substantially different from those occurring following license renewal, as identified in the GEIS (NRC 2013b) and in the decommissioning generic environmental impact statement (NRC 2002). These impacts would be temporary and would occur at the same time as the impacts from actions necessary to meet system generating needs.

7.2 Alternatives that Meet System Generating Needs

LSCS has an approximate annual average net capacity of 2,327 MWe (Exelon Corporation 2013a). LSCS generated approximately 19.3 terawatt-hours of baseload power in 2011, and 19.1 terawatt-hours of baseload power in 2010 (EIA 2013a). LSCS is considered a baseload generation station based on, for example, its 2010 capacity factor of approximately 95 percent (Exelon Corporation 2013b). This baseload power is sufficient to supply the electricity used by over 2,300,000 homes (Exelon Corporation 2013b), and would be unavailable to customers in the event the LSCS operating licenses are not renewed.

The electricity consumed in Illinois is not limited to that generated within the state. Northern Illinois relies on electricity from Commonwealth Edison Company (ComEd), an Exelon-owned energy delivery company that provides service to approximately 3.8 million customers, or 70 percent of the state's population (ComEd 2013). ComEd is the Illinois-based control zone of the PJM Interconnection, a regional network that coordinates the movement of wholesale electricity. PJM Interconnection comprises all or most of Delaware, the District of Columbia, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia and parts of Indiana, Illinois, Kentucky, Michigan, North Carolina, and Tennessee. The four fifths of southern Illinois that are not part of PJM Interconnection and the surrounding states are part of Midwest Independent Transmission System Operator (Midwest ISO). Midwest ISO comprises all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, Illinois, Indiana, Michigan and parts of Montana, Missouri, Kentucky, and Ohio. Exelon Generation assumed that the region of interest (ROI) for purposes of this alternatives analysis includes the states of Illinois, Indiana, Iowa, Michigan, Missouri, and Wisconsin which are the states within the PJM Interconnection or Midwest ISO networks that are geographically closest to LSCS.

The current power generation options in the ROI are indicators of what are considered to be feasible technologies for generating electricity within the area serviced by LSCS. In 2012, the ROI's electricity industry had a total generating capacity of 155,869 MWe. This capacity included units fueled by coal (46 percent), natural gas (29 percent), nuclear (12 percent), renewables and other sources (8.7 percent), petroleum (3.2 percent), and hydroelectric (0.9 percent) (EIA 2014). In 2012, electricity generators provided 633 terawatt-hours of electricity to the ROI. The fuel sources used to produce this electricity were dominated by coal (58 percent), followed by nuclear (24 percent), natural gas (10.6 percent), renewables and other sources (6.1 percent), hydroelectric (0.8 percent), and petroleum (0.3 percent) (EIA 2014). Figure 7.2-1 illustrates the distribution of fuel types contributing to the 2012 installed generating capacity and Figure 7.2-2, the electricity production of the ROI.

Comparing the fuel types comprising the generating capacity in the ROI with the fuel types actually utilized for electricity generation indicates that generating units fueled by nuclear and coal are used by the ROI substantially more relative to their installed capacity than either oil-fired or gas-fired generation. This condition reflects the relatively low fuel cost and baseload suitability for nuclear and coal-fired power plants, and the relatively limited use of gas- and oil-fired units to meet peak loads. Comparisons of installed capacity and energy production for oil- and gas-fired facilities indicates a strong preference for gas over oil, indicative of the higher cost and greater air pollutant emissions associated with oil. Energy production from hydroelectric sources is preferred from a cost standpoint over production from plants fueled by nuclear and any of the three fossil fuels, but hydroelectric capacity is limited and utilization can vary substantially depending on water availability.

7.2.1 Alternatives Considered

Technology Choices

For the purposes of this Environmental Report, alternative generating technologies were evaluated to identify candidate technologies that would be capable of replacing the LSCS annual average baseload capacity of approximately 2,327 MWe by the end of the first unit's licensed term in 2022. Exelon Generation accounted for the fact that LSCS is a baseload generator and that any reasonable alternative to LSCS would also need to be able to generate baseload power. Exelon Generation assumed that the ROI for purposes of this alternatives analysis includes the states of Illinois, Indiana, Iowa, Michigan, Missouri, and Wisconsin which are the states within the PJM Interconnection or Midwest ISO networks that are geographically closest to LSCS.

For the purposes of this Environmental Report, Exelon Generation has limited analysis of impacts from new generating plant technology alternatives to the technologies it deems reasonable or potentially reasonable by 2022: new nuclear generation, pulverized coal- and gas-fired generation, wind generation, and combinations of wind and solar generation with emerging storage technologies . The generation information presented above, which identifies coal as the most heavily used fuel in the ROI, supports consideration of a coal-fired alternative. The coal-fired technology that Exelon Generation has chosen to evaluate is the ultra-supercritical coal-fired boiler with control technologies recognized by EPA for minimizing emissions. As is more fully discussed in Section 7.2.1.6, Exelon Generation considered the Integrated Gasification Combined Cycle (IGCC) technology, but found that it currently is not cost-effective or widely demonstrated, and has lower system reliability than developers had projected.

The gas-fired technology alternative that Exelon Generation has chosen to evaluate is the combined-cycle (combustion and steam) turbine rather than the simple-cycle (combustion-only) turbine. The combined-cycle option is more efficient and economical to operate because it uses the heated exhaust of the combustion turbines to produce steam in Heat Recovery Steam Generators (HRSGs), which is then used in the steam turbines to generate additional power. The benefits of lower operating costs for the combined-cycle option outweigh its higher capital costs relative to the simple-cycle combustion turbine. Exelon Generation assumes natural gas would be the primary fuel in combined-cycle combustion turbines because of the economic and environmental advantages of natural gas over oil and other types of gas. Manufacturers now have large standard-sized combined-cycle turbines that are economically attractive and suitable for high-capacity baseload operation.

The ROI has 13 nuclear sites containing 20 of the nation's 100 operating nuclear reactors. Illinois has more nuclear plants than any other U.S. state with 6 nuclear sites and 11 reactors. Approximately 19 percent of the nation's nuclear capacity is within the ROI, and more than 11 percent is within Illinois (EIA 2013a). Beginning in 2007, several utilities submitted applications for combined construction and operation licenses (COLs) for new nuclear generating units. In February, 2012, the NRC granted Southern Company COLs to build and operate two nuclear reactors at Vogtle Electric Generating Plant, near Waynesboro, Georgia (SNC 2012) and in March, 2012, the NRC granted SCE&G COLs to construct and operate two nuclear reactors at the V. C. Summer Nuclear Station in South Carolina (SCE&G 2012). In light of this, Exelon Generation believes construction of new nuclear capacity within the ROI should be a reasonable baseload generation alternative to license renewal for the LSCS units and analyzes it as such in this Environmental Report. However, in 1987 Illinois issued a moratorium on new nuclear plant construction (220 ILCS 5/8-406(c)). Accordingly, construction in Illinois could not be considered unless the state lifted the ban.

Exelon Generation assumes that provision of wind-generated electricity in the ROI is likely to include both land-based and offshore plants. Two solar technologies have emerged as possible candidates for centralized electricity generation—photovoltaic (PV), and concentrating solar power (CSP) systems. While obstacles exist to the use of wind and solar energy technologies for baseload electrical capacity in the amount that would be needed to replace the LSCS units, Exelon Generation assumes that future technological advances may occur such that pure wind generation could, by 2022, become reasonable baseload generation alternatives to LSCS license renewal.

Currently, the intermittent nature of both wind and solar generation creates grid-reliability issues that make both energy sources unsuitable for baseload generation unless they are combined with some method of capacity firming. For this reason, Exelon Generation assumes for the purpose of this alternatives analysis that wind- or solar-generation facilities in combination with capacity-firming methods would also be reasonable alternatives to LSCS license renewal. Methods for providing firming capacity involve combining wind or solar energy with another electrical power source capable of providing electrical output when the wind or solar energy source is not available; ensuring that reliability of the electrical grid system is maintained. In addition to traditional fossil-fuel-fired generating units, suggested firming capacity sources include compressed air energy storage (CAES), high energy batteries, pumped hydro storage, and interconnected wind farms. Traditional fossil-fuel-fired generation options are described in Section 7.2.1.1. The other sources of firming capacity are described below along with discussions of whether or not Exelon Generation considers them reasonable capacity firming methods for purposes of LSCS license renewal.

Firming Capacity Methods

Compressed Air Energy Storage

CAES is a hybrid generation/storage technology with potential for balancing the electrical output from renewable energy power generators to improve their suitability for baseload capability. CAES systems are based on conventional gas turbine technology and use the potential energy of compressed air. As of 2010, worldwide installations total 440 MWe (EPRI 2010). Energy would be stored by using wind-generated power to compress air either in an airtight underground storage cavern, a surface vessel, or a surface piping system. A principal method to extract the stored energy uses compressed air drawn from the storage vessel, heated, and then expanded through a high-pressure turbine that captures some of the energy in the compressed air. The air would then be mixed with fuel and combusted, with the exhaust expanded through a low-pressure gas turbine. The turbines would be connected to an electrical generator. As part of a baseload renewable energy generation system, CAES theoretically could enable a nearly constant output by smoothing the highly variable output from the renewable energy generator. CAES is considered a hybrid generation/storage system because it requires combustion in the gas turbine. The primary disadvantages of CAES are the need for a reservoir and its reliance on fossil fuels. Assessments of this concept by the National Renewable Energy Laboratory (NREL) included a combination of 2,000 MWe of wind generation with 900 MWe of CAES generation to produce a nearly constant 900 MWe output (NREL 2006). The largest commercial CAES that has been proposed is an 800 MWe (with a potential expansion to 2,700 MWe) plant planned for construction in Norton, Ohio. This nine-unit plant will compress air to 1,500 pounds per square inch (psi) in an existing limestone mine some 671 m (2,200 ft) underground (UTA 2009). The estimated cost of such a facility in 2008 was in the range of $650 per kilowatt-hour (kWh) with energy conversion efficiency in the range of 80 percent (PEI 2008). To date, there are two operating CAES plants in the world; a 110 MW plant in McIntosh, Alabama, commissioned in 1991 and a 290 MW plant in Huntorf, Germany built in 1978. Both plants store air underground in excavated salt caverns produced by solution mining, but underground salt formations are found in relatively few locations geographically. Numerous studies have been undertaken of traditional CAES storage in more prevalent underground porous and permeable rock structures. While studies indicate geological features necessary for building a utility-scale CAES facility may be found in Illinois (PEI 2008), proposed Illinois locations such as Brocton and Hume have not been developed. The Iowa Energy Storage Park, which proposed coupling CAES with wind by using aquifers for air storage, was terminated because of site geological limitations. Lessons learned from the Iowa project indicate greater difficulty implementing CAES in an aquifer reservoir relative to other underground storage opportunities such as caverns, mined salt formations, or depleted natural gas reservoirs (SNL 2012). Given that lengthy site-specific investigations would be needed to determine whether a suitable geologic formation is available to accommodate CAES and the lack of success for CAES projects in the ROI, Exelon Generation does not consider a combination of wind generation with CAES to be a reasonable firming capacity method for the purpose of the alternatives analysis and, thus, impacts are not evaluated further.

High-Energy Batteries

High-energy batteries can generally provide rapid response, which means that batteries designed for energy management can potentially provide services over all the durations required. Several battery technologies have been demonstrated or deployed for energy management applications. The commercially available batteries targeted to energy management include two general types: high-temperature batteries and liquid-electrolyte-flow batteries. The most mature high-temperature battery as of 2010 is the sodium-sulfur battery, which has a worldwide installation that exceeds 316 MWe (EPRI 2010). Alternative high-temperature chemistries have been proposed and are in various stages of development and commercialization. One example is the sodium-nickel chloride ("ZEBRA") battery. The second type of high-energy battery is the liquid-electrolyte-flow battery which consists of a liquid electrolyte flowing across a membrane. As of 2009, there was limited deployment of two types of flow batteries: vanadium redox and zinc-bromine. Other chemical combinations such as polysulfide-bromine have been pursued, and new chemistries are under development. In the US, a primary application of energy-management batteries has been transmission and distribution deferral. Demonstration projects have been deployed for various other applications, but there are no current applications or demonstration studies of battery storage systems that approach the reserve capacity required for balancing the output from a wind generation power plant of the size necessary to replace the LSCS approximate annual average net baseload generating capacity of 2,327 MWe (EPRI 2010). Because this method for balancing intermittent output from large wind generation facilities has not been demonstrated, Exelon Generation does not consider it to be a reasonable firming capacity method and, thus, impacts of combining it with wind generation are not evaluated further.

Pumped Hydro Storage (PHS)

PHS is the only energy storage technology deployed on a gigawatt (GW) scale in the U.S. and worldwide. In the U.S., about 20 GW is deployed across 39 sites, and installations range in capacity from less than 50 MWe to 2,100 MWe. The ROI has 2,528 MWe capacity in pumped storage (EIA 2014). Many of the sites store sufficient water for 10 hours or more of discharge (some have storage capacity for 20 hours or more of discharge), making the technology useful for supplementing wind. PHS uses conventional pumps and turbines and requires a significant amount of land and water for the upper and lower reservoirs. PHS plants can achieve round-trip efficiencies that exceed 75 percent. Environmental regulations may limit large-scale above-ground PHS development. However, given the high round-trip efficiencies, proven technology, and low cost compared to most alternatives, conventional PHS is still being pursued in a number of locations (NREL 2010a). A PHS station costs in excess of $1,500/kW (EPRI 2010).

The ideal operating head is between 500 and 700 m (1,500 and 2,200 ft) of elevation (NWW 2009). The environmental impacts of large-scale PHS facilities are becoming an issue because pre-existing reservoirs are not available and sites with large, naturally occurring reservoirs at sufficiently large differential elevations where environmentally benign, inexpensive PHS facilities can be built are increasingly rare (PEI 2008). The feasibility of implementing PHS in the ROI would depend on availability of a suitable water reservoir, which would require detailed site-specific investigation. Because this method for balancing intermittent output from wind generation facilities would be very resource- and capital-intensive, involving construction of a reservoir at an as-yet unidentified location in proximity to a site suitable for wind generation, Exelon Generation does not consider PHS to be a reasonable firming capacity method compared with other available methods. Accordingly, impacts of combining it with wind generation are not evaluated further.

Interconnecting Wind Farms

The concept of developing baseload wind energy by interconnecting wind farms through the transmission grid postulates that, if wind farms are interconnected in an array, wind speed correlation among sites decreases and so does the probability that all sites experience the same wind regime at the same time. As the array size increases, theoretically it would behave more and more like a single wind farm with steady wind speed and, thus, steady deliverable wind power.

One study (Archer, et al. 2007) used hourly and daily averaged wind speed measurements from 19 airports in the Texas, New Mexico, Oklahoma, and Kansas to estimate generation duration curves and operational statistics of wind power arrays. Archer and Jacobson (Archer and Jacobson 2007) found that “an average of 33 percent and a maximum of 47 percent of yearly averaged wind power from interconnected farms can be used as reliable, base-load electric power.” The area of interest the authors chose for their wind model (the lower Midwestern states) is one of the best locations in the country for harnessing wind energy. Wind farms in the ROI, with the possible exception of western Iowa, would be located where conditions are not as favorable. Archer and Jacobson (Archer and Jacobson 2007) used capacity factor as an indicator of reliability, but capacity factor and reliability are two separate and distinct parameters. During a scheduled outage of a conventional power plant, the power output is guaranteed to be zero; there is no uncertainty. Maintenance outages scheduled long in advance reduce a plant’s capacity factor, not its reliability. Archer and Jacobson (Archer and Jacobson 2007) compare the scheduled down time of conventional power plants with the unscheduled unpredictable downtime of wind power. If reliability of wind farms were compared to reliability of conventional power plants, this comparison would demonstrate that wind farms, even when interconnected in an array, are not as reliable as conventional power plants.

Another study (Katzenstein, et al. 2010) used output data from 20 wind farms within the Electric Reliability Council of Texas (ERCOT) region, and wind speed data to analyze the geographic smoothing of wind power's variability. The Katzenstein et al. study (2010) also used data from 19 Bonneville Power Authority (BPA) wind farms to determine if results similar to the ERCOT results could be expected from another system. Katzenstein et al. (Katzenstein, et al. 2010) determined that the variability of interconnected wind farms is less than that of individual wind farms and the variability diminishes as more wind farms are interconnected. The Katzenstein et al. study concluded that “these results do not indicate that wind power can provide substantial base-load power simply through interconnecting wind plants. ERCOT’s generation duration curve shows wind power reliably provides 3 - 10 percent of installed capacity as firm power; while BPA’s generation duration curve shows 0.5 - 3 percent of its wind power is firm power. The frequency domain analyses have shown that the power of interconnected wind plants will vary significantly from day to day and the results of the step change analyses show day-to-day fluctuations can be 75 to 85 percent of the maximum power produced by a wind plant" (Katzenstein, et al. 2010). Based on this discussion, Exelon Generation believes that interconnected wind farms have some advantages over a single large-scale wind farm, but the predicted low capacity factor and reliability combined with the likely need of extensive right-of-way acquisition and transmission line construction at significant costs, makes interconnected wind farms not a reasonable firming capacity method at this time.

Effects of Restructuring

Nationally, the electric power industry has been undergoing a transition from a regulated industry to a competitive market environment. Efforts to deregulate the electric utility industry began with passage of the National Energy Policy Act of 1992. Provisions of this act required electric utilities to allow open access to their transmission lines and encouraged development of a competitive wholesale market for electricity. The Act did not mandate competition in the retail market, leaving that decision to the states (EIA 2010a). In 1997 and 2000, Illinois and Michigan transitioned to competitive wholesale and retail markets, respectively. The other states in the ROI have not restructured their retail energy markets.

In 1997, Illinois state lawmakers passed the Illinois Electric Service Customer Choice and Rate Relief Law, which deregulated the state's two biggest electricity utilities; Ameren Illinois Utilities, formerly Illinois Power Co., and ComEd, and gave customers the ability to purchase electricity from alternative retail electric suppliers (ARES) that had been approved to do business in the state (EIA 2009). In the decade between 1997 and 2007, called the Mandatory Transition Period, the power to choose an electric provider was reserved mostly for large commercial and industrial customers; residential and small business customers weren't allowed to purchase their electricity from an ARES and were forced to remain with their utility. However, in order to protect residential and small business customers, the Illinois Commerce Commission, which oversees the state's public utilities, reduced the price of electricity by 20 percent and froze the rate for 10 years. During the Mandatory Transition Period, utilities were required to sell their electricity generation assets to other affiliated and unaffiliated energy companies and became companies that only delivered electricity (ICC 2009).

In 2006, the Illinois General Assembly helped the state's many ARES to begin serving residential and small business customers by passing the Retail Electric Competition Act. The act established the Office of Retail Market Development, removed certain barriers to competition, and encouraged residential and small business customers to switch to an alternative electric provider by promoting temporary, fixed-discount programs. (ICC 2009)

Residential customers saved an estimated $5.2 billion between 1998 and 2006 because of the rate caps. Immediately after the caps on the utilities' electric rates expired Jan. 1, 2007, the cost of electricity in Illinois soared (ICC 2009). The resulting price shock from the inevitable price increases once the rate caps expired led to significant criticism of, and amendments to, the Customer Choice Act. In the summer of 2007, the state's General Assembly passed the Illinois Power Agency Act, which created the Illinois Power Agency and provided over $1 billion in new electricity rate relief over 4 years to residential and certain commercial customers (ICC 2009). By 2013, there were 87 companies statewide certified as an ARES through the Illinois Commerce Commission (ICC 2013). Of those, 57 have obtained Illinois Commerce Commission certification and registration to serve residential customers. However, in order to offer retail electric services in Illinois, suppliers must also register with the electric utility and complete certain technical testing. Thirty-three suppliers within the Ameren Illinois Utilities territory have completed the registration process and 32 of those suppliers were actively selling electricity in the territory as of December 2012. In ComEd's territory, 60 suppliers have completed the registration process and 51 of those suppliers were actively selling electricity as of December 2012 (ICC 2013).

In 1997, the Michigan Public Service Commission ordered Michigan's electric utilities to develop plans to allow all customers to choose their own electric generation supplier. In 2000, Michigan's Customer Choice and Electricity Reliability Act took effect, giving all customers of Michigan's investor-owned utilities the ability to choose an alternative electric supplier. Michigan's electric industry was restructured so that the generation and supply of electricity became open to competitive suppliers. The electric transmission and distribution businesses remain under a regulated utility structure (MPSC 2012; EIA 2008).

When electric restructuring was introduced in 2000, Michigan's largest utilities, Detroit Edison and Consumers Energy immediately enacted a 5 percent rate reduction and further reductions were introduced in 2005 (EIA 2008). In 2008, the Michigan legislature passed a bill that essentially "re-regulated" the market and limited customer choice enrollments to 10 percent of the total utility sales in each territory (MPSC 2013). One aim of this legislation was to provide Detroit Edison and Consumers Energy a stable base of ratepayers upon which the utilities could rely to fund new generation projects. At present, five Michigan utilities have active choice participation. Consumers Energy and Detroit Edison, along with Upper Peninsula Power Company and Wisconsin Electric Power Company are fully subscribed at the 10 percent cap while Wisconsin Public Service Company is just below the cap. Hypothetically, if the cap did not exist, choice participation would be approximately 25 percent for Consumers Energy and 22 percent for Detroit Edison. (MPSC 2014). Legislation introduced in December 2013 (House Bill 5184) would remove the 10 percent cap and re-open Michigan's electricity market to full competition.

Renewable Portfolio Standards

A renewable portfolio standard is a state policy that requires electricity providers to get a minimum percentage of their power from renewable energy resources by a certain date. As of March 2013, 29 states plus the District of Columbia have renewable portfolio standards (RPS) or other mandated renewable capacity policies in place, and 8 states have voluntary goals for renewable generation. These 37 states include Illinois, Indiana, Iowa, Michigan, Missouri, and Wisconsin (DSIRE 2013a).

In August 2007, Illinois enacted legislation (Public Act 095-0481) that created the Illinois Power Agency. The Illinois Power Agency plans and administers the competitive procurement processes that result in bilateral agreements between the utilities and wholesale electric suppliers. The procurement plans must include procurement of cost-effective renewable energy resources per RPS which requires that by 2026, 25 percent of electricity sold by electric utilities and ARES come from renewable sources such as solar thermal electric, PVs, landfill gas, wind, biomass, hydroelectric, anaerobic digestion, and biodiesel. Additionally, 1.50 percent of electric utilities and ARES sales must be from solar sources, 18.75 percent of electric utilities sales from wind sources, 15.00 percent of ARES sales from wind sources, and 0.25 percent of electric utilities sales from distributed generation. In order for a system to qualify under the distributed generation requirement, systems must be 2 MWe or less and powered by renewable sources. (DSIRE 2013a)

In May 2011, Indiana passed Senate Bill 251, creating its Clean Energy Portfolio Standard. The program sets a voluntary goal of 10 percent clean energy by 2025, based on 2010 levels. In order to participate in the program, qualifying electric utilities must apply to the Indiana Utility Regulatory Commission. Participation in Clean Energy Portfolio Standard makes utilities eligible for incentives to pay for the compliance projects. Only public utilities may participate in the program; municipally-owned utilities, rural electric cooperatives, or electric cooperatives with at least one rural electric cooperative member may not participate in the program. Eligible technologies include wind, solar, dedicated energy crops, organic waste biomass, hydropower, fuel cells, energy storage systems, geothermal energy, coal bed methane, demand side management or energy efficiency initiatives, nuclear energy, natural gas that displaces electricity from coal, and clean coal technology (DSIRE 2013a).

Iowa requires its two investor-owned utilities (MidAmerican Energy and Alliant Energy Interstate Power and Light) to own or to contract for a combined total of 105 MWe of renewable generating capacity and associated energy production. Eligible resources include solar, wind, waste management, resource recovery, refuse-derived fuel, agricultural crops or residues, wood-burning facilities, or small hydropower facilities (DSIRE 2013a).

In October 2008, Michigan enacted the Clean, Renewable, and Efficient Energy Act (Public Act 295), requiring the state's investor-owned utilities, alternative retail suppliers, electric cooperatives and municipal electric utilities to generate 10 percent of their retail electricity sales from renewable energy resources by 2015. In addition to renewables, the standard allows utilities to use energy optimization (energy efficiency) and advanced cleaner energy systems to meet a limited portion of the requirement. The state's two largest investor-owned utilities, Detroit Edison and Consumers Energy, have additional obligations beyond those of other utilities. Under the standard, eligible renewables include biomass, solar and solar thermal, wind, geothermal, municipal solid waste, landfill gas, existing traditional hydroelectric (i.e., water passed through a dam), tidal, wave, and water current (e.g., run-of-river hydroelectric) resources. The definition of energy optimization is synonymous with what is generally defined as energy efficiency. In order to be counted under the standard, energy efficiency measures must reduce customer consumption of energy, electricity, or natural gas. Advanced cleaner energy facilities are loosely defined as electric generating facilities using a technology that is not in commercial operation. In addition to the percentage-based energy requirements, Consumers Energy must meet a renewable energy capacity standard of 500 MWe by 2015 and Detroit Edison must meet a renewable energy capacity standard of 600 MWe by 2015. Energy production from these new renewable energy facilities can be counted towards the percentage-based component of the standard (DSIRE 2013a).

In June 2007, Missouri created a voluntary renewable energy and energy-efficiency objective for the state's investor-owned utilities. The objective required each utility to make a "good-faith effort" to generate or procure renewable electricity equivalent to 11 percent by 2020. In November 2008, voters in Missouri repealed the state’s existing voluntary renewable energy and energy efficiency objective and replaced it with an expanded, mandatory renewable electricity standard of 15 percent by 2021. The standard also requires that by 2021, 0.3 percent of retail electricity sales must be derived from solar energy. Like the prior voluntary objective, the new standard applies only to the state’s investor-owned utilities and does not place any requirements on municipal utilities or electric cooperatives. Eligible renewables are defined as electricity produced using solar PVs; solar thermal; wind; small hydropower; biogas from agricultural operations, landfills and wastewater treatment plants; pyrolysis and thermal depolymerization of waste materials; various forms of biomass; fuel cells using hydrogen from renewable resources; and other renewable-energy resources approved by the Missouri Department of Natural Resources (DSIRE 2013a).

In 1998 Wisconsin enacted Act 204, requiring regulated utilities in eastern Wisconsin to install an aggregate total of 50 MWe of new renewable-based electric capacity by 2000. In 1999 Wisconsin enacted Act 9, becoming the first state to enact a RPS without having restructured its electric-utility industry. Wisconsin's RPS originally required investor-owned utilities and electric cooperatives to obtain at least 2.2 percent of the electricity sold to customers from renewable-energy resources by 2012. Legislation enacted in 2006 increased renewable-energy requirements and established an overall statewide renewable-energy goal of 10 percent by 2015. Qualifying electricity generating resources include tidal and wave action, fuel cells using renewable fuels, solar thermal electric and PV, wind power, geothermal, hydropower, and biomass (including landfill gas) (DSIRE 2013a).

Descriptions of Alternatives

The following sections present fossil-fuel-fired (coal or natural gas) generation capacity (Section 7.2.1.1), purchased power (Section 7.2.1.2), new nuclear generation capacity (Section 7.2.1.3), wind energy (Section 7.2.1.4), and combinations of various energy supplies (Section 7.2.1.5) as alternatives that Exelon Generation hypothesizes for purposes of this environmental report, would be reasonable alternatives to license renewal. Section 7.2.1.6 discusses additional alternatives that Exelon Generation has determined are not reasonable and the bases for these determinations.

Construction of any hypothetical power station at LSCS or another existing power station site would be preferable to construction at a greenfield site. Environmental impacts would be minimized by building on previously disturbed land and by making the most use possible of existing infrastructure, such as transmission lines, roads and parking areas, office buildings, and components of the cooling system. Therefore, except for the wind generation alternative, without identifying a specific location for such new construction at a specific site in the ROI, for the purpose of the analysis, Exelon Generation assumed that space would be found at LSCS or another existing power plant site within the ROI in order to benefit from the existing infrastructure and minimize the environmental impacts that would occur at a greenfield location. This approach avoids overstating the environmental impacts of these alternatives in comparison to the proposed action. Because of the large land use demands of new wind generation facilities, Exelon Generation assumes that even if the LSCS site or other existing plant sites were used, doing so would not significantly reduce the total greenfield acreage that would be required.

To compare the environmental impacts of alternative electricity generation with LSCS license renewal on an equal basis, Exelon Generation set the existing approximate net average annual generating capacity of LSCS, 2,327 MWe (Exelon Corporation 2013a), as the approximate net electrical generating capacity that any reasonable alternative would need to supply. However, because some alternative technologies are manufactured in standard unit sizes, it was not always possible to aggregate such technologies to exactly match the LSCS capacity.

It must be emphasized, however, that all scenarios are hypothetical. Exelon Generation has no current plans for new facility construction to replace LSCS.

7.2.1.1 Construct and Operate New Natural Gas-Fired or Coal-Fired Generation Capacity

Gas-Fired Generation

For purposes of this analysis, Exelon Generation assumed development of a natural gas-fired combined-cycle plant with design characteristics similar to those being developed elsewhere in the ROI, and with a net generating capacity comparable to that of LSCS. The hypothetical plant would comprise six pre-engineered natural gas-fired combined-cycle units producing 400 MWe each of net plant power for a total of 2,400 MWe (GE Energy 2007). The characteristics of this plant and other relevant resources were used to define the gas-fired alternative. Table 7.2-1 presents the basic characteristics for the gas-fired alternative, and impacts are described in Section 7.2.2.1.

Coal-Fired Generation

NRC has routinely evaluated coal-fired generation alternatives for nuclear plant license renewal. In defining the coal-fired alternative to LSCS, specific characteristics of coal commonly used in the ROI have been used for direct comparison with a gas-fired plant producing 2,400 MWe (net).

For purposes of this analysis, Exelon Generation assumed the coal-fired alternative would be composed of four 600-MWe (net) ultra-supercritical coal-fired boilers for a total of 2,400 MWe. Table 7.2-2 presents the basic coal-fired alternative emission control characteristics, and impacts are described in Section 7.2.2.2. The emissions control assumptions are based on the technologies recognized by the EPA for minimizing emissions and calculated emissions based upon the EPA published removal efficiencies (EPA 1998a). As is more fully discussed in Section 7.2.1.7, Exelon Generation considered the Integrated Gasification Combined Cycle (IGCC) technology, but found that it currently is not cost-effective or widely demonstrated, and has lower system reliability than developers had projected.

7.2.1.2 Purchased Power

Exelon Generation has evaluated conventional and prospective power supply options that could be reasonably implemented before the existing LSCS licenses expire. As noted in Section 7.2.1, electric industry restructuring initiatives in the ROI are designed to promote competition in energy supply markets by facilitating participation by non-utility suppliers. PJM and Midwest ISO have implemented market rules to appropriately anticipate and meet electricity demands in the wholesale electricity market that has resulted from restructuring. However, because retail customers in the ROI now may choose among multiple companies to supply their electricity needs, future load obligations of any company in the ROI are uncertain. For the purposes of this analysis, Exelon Generation made the assumption that the PJM and Midwest ISO member companies would install electricity generation capacity beyond that necessary to meet the currently anticipated future demand, so as to make purchased power a reasonable alternative for meeting load obligations in the event the existing operating licenses for LSCS are not renewed.

The technologies that would be used to generate purchased power are unknown. Even so, Exelon Generation believes it is likely that the generating technologies analyzed by the NRC in the GEIS would be the primary sources of purchased power. For this reason, Exelon Generation is adopting by reference the GEIS description of the alternative generating technologies to represent the purchased power alternative. Of these technologies, facilities fueled by coal and combined-cycle facilities fueled by natural gas are the most cost effective for providing baseload capacity. Impacts are described in Section 7.2.2.3.

Exelon Generation anticipates that additional transmission infrastructure would be needed in the event purchased power must replace LSCS capacity. From a local perspective, loss of LSCS could require construction of new transmission lines to ensure local system stability. From a regional perspective, PJM and Midwest ISO's inter-connected transmission system is highly reliable.

7.2.1.3 Construct and Operate New Nuclear Generating Capacity

Since 1997, the NRC has certified four new standard designs for nuclear power plants under 10 CFR Part 52, Subpart B. Reactor designers currently are developing small light-water reactors and non-light water reactors. (NRC 2014)

The NRC staff considered new nuclear generating capacity within the ROI for the Clinton Early Site Permit (NRC 2006). In its analysis, the NRC staff evaluated a bounding case of 2,200 MWe of new nuclear generation that would be installed in the form of either one or two units of a certified design. Impact analyses did not reference a particular design, and impacts generally applicable to all certified designs were assumed. Exelon Generation has reviewed the NRC analysis of new nuclear capacity for the Clinton site, believes it to be sound, and notes that it addresses less capacity than the approximate 2,327 MWe discussed in this analysis; however, for comparison with LSCS license renewal, that provides a conservative estimate of potential impacts. Exelon Generation has assumed construction at an existing plant site of two new nuclear units of a certified design. Impacts are described in Section 7.2.2.4.

7.2.1.4 Wind Energy

Energy potential in wind is expressed by wind generation classes, ranging from 1 (least energetic) to 7 (most energetic). Current wind technology can operate economically on Class 4 sites with the support of the Federal production tax credit of 2.3 cents per kWh for plants that began construction by December 31, 2013 (DOE 2008; DSIRE 2013b), while technology to generate electricity from Class 3 wind requires further technical development for utility scale application. In the ROI, areas of highest wind energy (Class 4 and 5) are the western portions of Iowa; a pocket in Benton County, Indiana about 130 km (80 mi) southeast of LaSalle; and the offshore areas of Lake Michigan, Lake Superior, and Lake Huron (NREL 2011a). As of September, 2011, the ROI had an installed wind generating capacity totaling approximately 8,600 MWe; Illinois had 2,436 MWe, Indiana 1,339 MWe, Iowa 3,708 MWe, Missouri 459 MWe, Michigan 185 MWe, and Wisconsin 469 MWe (NREL 2011b). PJM Interconnection and Midwest ISO have active or under construction wind projects totaling approximately 19 GW and 18 GW, respectively, as of 2013 (PJM 2014) MISO Undated). Several Great Lakes states, including Illinois and Michigan, and federal agencies entered into a Memorandum of Understanding in 2012 regarding offshore wind energy (Associated Press 2012). Illinois enacted the Lake Michigan Wind Energy Act in 2013 (Public Act 98-0447) to establish a framework for leasing Michigan's Great Lakes bottomlands and permitting offshore wind energy systems. No off-shore wind energy projects were operable in the ROI at the end of 2013 (Progress Illinois 2013).

Due to the intermittent nature of wind, wind power plants cannot reliably be ramped up quickly to a required level of output; therefore regional networks grant new wind facilities a percentage of the name plate capacity as credit to meeting peak demand load ("effective capacity" or "capacity credit"). PJM Interconnection and Midwest ISO grant new wind facilities 13 percent and 14.7 percent capacity credit, respectively (PJM 2010a; MISO 2011). Accordingly, to replace the LSCS approximate annual average net baseload generating capacity of 2,327 MWe, assuming the Midwest ISO current-day capacity credit for wind generation, approximately 14,250 MWe of new wind capability would be required ([new wind capability] x 0.147 = 2,327 MWe x 0.90; assuming a capacity factor of 90 percent for LaSalle). However, by 2025 (three years after the LSCS Unit 1 license expires), new land-based and offshore wind projects could theoretically achieve capacity factors (the ratio of actual energy output over the highest-load period to the hypothetical maximum energy output capability over that same period) as high as 49 percent and 51 percent, respectively, as a result of technology improvements and operating experience (DOE 2008). Therefore, assuming a future capacity credit for wind generation based on an average of the theoretically projected capacity factors for land-based and offshore projects, approximately 4,270 MWe of new wind capability would be required to replace the baseload generating capacity of LSCS.

The intermittent nature of wind causes fluctuations that can change power frequency which, in turn, can affect grid-reliability when wind energy supplies electricity to the transmission grid. For this reason, methods to mitigate the grid-reliability impacts of generating electricity with intermittent wind energy (see Section 7.2.1) must be applied to allow current-day wind energy facilities to provide baseload generation capacity (NREL 2010a). Even so, for the purposes of this Environmental Report, it is assumed that a wind plant with no firming capacity could be a reasonable alternative in the future. Hence, impacts from a purely wind energy alternative are described in Section 7.2.2.5. Section 7.2.2.6 discusses impacts from wind energy combined with solar energy and gas-fired combined-cycle firming capacity.

Exelon Generation anticipates that additional transmission infrastructure would be needed to integrate wind energy generation into the regional electricity grid if this alternative is used to replace LSCS's baseload generating capacity.

7.2.1.5 Combinations of Alternatives

For the purpose of comparison, Exelon Generation has crafted an alternative that combines generation alternatives to replace LSCS's approximate annual average net baseload generating capacity. The combination considered is wind generation combined with PV solar generation and firming capacity in the form of gas-fired combined-cycle generation .

Exelon Generation assumes that this combination of generation alternatives could adequately balance the electrical output from intermittent wind and solar energy sources to allow these sources to replace LSCS's baseload generating capacity by the end of the first licensed unit's term in 2022.

<u>Wind Generation, PV Solar Generation, and Gas-Fired Combined-Cycle Generation</u>

Wind and solar generation appear to be appropriate components of this combination alternative because renewable energy sources, including wind and solar energy, are projected to be a growing source of electricity through 2040 (EIA 2013b). Moreover, PJM Interconnection reports that as of 2011 about 34 GW of wind generation has been proposed for construction in the PJM region, and about 4 GW of solar generation has been proposed (PJM 2014). Additionally, Midwest ISO reports that as of 2011 about 27 GW of wind generation has been proposed for construction in the Midwest ISO region (MISO Undated). Because most power plants added to the U.S. electricity grid since 1990 have been gas-fired combined-cycle units, it is also appropriate to assume that the method by which firming capacity for wind and solar power would be provided is a new gas-fired combined-cycle generation plant. Furthermore, the Energy Information Administration's Annual Energy Outlook forecasts continued growth in the use of gas-fired combined-cycle plants as a new electricity source through 2035 (EIA 2013b). Hence, gas-fired combined-cycle electricity generation is a proven technology with demonstrated operating characteristics and well-defined resource and capital requirements.

For this combination of alternatives, Exelon Generation assumed that 1,200 MWe of LSCS's net baseload capacity of 2,327 MWe would be replaced by one land-based wind farm, with the balance (1,130 MWe) replaced by three PV solar facilities. However, because wind and PV solar energy are intermittent, for the purpose of this alternative, the wind farm capacity credit is assumed to be 49 percent (based on the projected capacity factor for land-based wind energy in 2025 [Section 7.2.1.4]), and the PV solar facility capacity credit is assumed to be 38 percent (the current-day PJM Interconnection capacity credit for solar [Section 7.2.1.5]). As a result, the total capacity assumed for the wind farm is 2,200 MWe and the total capacity assumed for each of the three PV solar facilities is 900 MWe, for a total PV solar generating capacity of 2,700 MWe.

Gas-fired combined-cycle generation has been successfully used to balance intermittent renewable power and thereby maintain electrical grid system reliability. Based on an ICF International analysis of the firming capacity needed to meet shortfalls between actual wind output and forecast wind output (ICF International 2011), approximately 28.5 percent of wind energy forecast would be needed in gas-fired combined-cycle backup to support the regulation and operating reserve requirements imposed by wind energy. Assuming 2,200 MWe of land-based wind generation capability, approximately 627 MWe of gas-fired combined-cycle generation would be required as reserve capacity.

Comparable estimates of the amount of gas-fired combined-cycle backup needed to support the regulation and operating reserve requirements imposed by solar generation were not found in the literature. Therefore, for the purposes of this evaluation, Exelon Generation has assumed that approximately 10 percent of PV solar energy capability would be needed in gas-fired combined-cycle backup. Accordingly, for 2,700 MWe of PV solar energy capability (assuming the current PJM Interconnection capacity credit for solar of 38 percent), approximately 270 MWe of gas-fired combined-cycle generation would be required as reserve capacity.

In summary, for this combination of alternatives, Exelon Generation assumed that the LSCS baseload capacity of 2,327 MWe would be replaced by one 2,200 MWe wind farm (with one 400 MWe and two 130-MWe gas-fired combined-cycle backup unit) and three 900 MWe PV solar facilities (each with a 90 MWe gas-fired combined-cycle backup unit). Also, for the purposes of this Environmental Report, it is assumed that, by 2022, this combination of alternatives would be a reasonable alternative to the renewal of the LSCS operating licenses. Impacts of this alternative are discussed in Section 7.2.2.7.

7.2.1.6 Other Alternatives

This section identifies alternatives that Exelon Generation has evaluated and determined are not reasonable for replacing LSCS and the bases for these determinations. Exelon Generation accounted for the fact that LSCS is a baseload generator and that any feasible alternative to LSCS would also need to be able to generate baseload power. Except for the discussion of demand-side management, Exelon Generation relied upon the GEIS in performing this evaluation (NRC 2013b).

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC) is an emerging advanced technology for generating electricity with coal that combines modern coal gasification technology with both gas turbine and steam turbine power generation. The technology is substantially cleaner than conventional pulverized coal plants because major pollutants can be removed from the gas stream prior to combustion.

The IGCC technology generates substantially less solid waste than the pulverized coal-fired process. The largest solid waste stream produced by IGCC installations is slag, a black, glassy sand-like material that is potentially a marketable byproduct. Slag production is a function of ash content in the coal. The other large-volume byproduct produced by IGCC plants is sulfur, which is extracted during the gasification process and can be marketed rather than placed in a landfill. IGCC units do not produce ash or scrubber wastes.

At present IGCC technology still has insufficient operating experience for widespread expansion into commercial-scale, utility applications. Each major component of IGCC has been broadly utilized in industrial and power generation applications, but the integration of coal gasification with a combined-cycle power block to produce commercial electricity as a primary output has only been demonstrated at a handful of facilities around the world, including six in the U.S. Experience has been gained with the chemical processes of gasification, coal properties and their impact on IGCC design, efficiency, and economics. However, system reliability is still lower than conventional pulverized coal-fired power plants. (SUFG 2007)

More than three dozen IGCC projects were proposed in the U.S. over the last decade. Currently only two IGCC projects have moved to construction, while dozens have been cancelled or replaced with natural gas units (Coal Age 2012). Southern Company is constructing a 582 MW IGCC project in Kemper County, Mississippi. Duke Energy's 618 MW Edwardsport Generating Station in Knox County, Ind., began commercial operations in June 2013. The Edwardsport Generating Station is the first use of IGCC technology on that scale in the U.S.

Overall, IGCC plants are estimated to be about 15 to 20 percent more expensive than comparably sized pulverized coal plants, due in part to the coal gasifier and other specialized equipment. Because IGCC technology currently is not cost-effective or widely demonstrated, and has lower system reliability, Exelon Generation does not consider IGCC facilities to be a reasonable alternative to LSCS license renewal.

Demand Side Management

Demand side management (DSM) programs include energy conservation and load management measures. Companies whose sole business is that of generating electricity and selling it to the wholesale market have no ability to implement DSM. Consequently, the NRC determined that NEPA does not require that an alternative involving electricity demand reduction through DSM be considered when the project purpose is to authorize a power plant to supply existing and future electricity demand (NRC 2006). The NRC determination was upheld by the US Court of Appeals for the Seventh Circuit (U.S. Court of Appeals for the Seventh Circuit 2006). Nevertheless DSM is considered here because energy efficiency and demand response (also known as load response) are important tools for meeting projected electricity demand.

Historically, state regulatory bodies required regulated utilities to institute programs designed to reduce demand for electricity, and revenues were adjusted through the regulated ratemaking process. In a deregulated, competitive electric wholesale market, however, private companies engage in marketing the energy, capacity, and ancillary services from their generating facilities in wholesale markets managed by regional transmission organizations, such as PJM Interconnection.[8]

In parts of Illinois, Indiana, and Michigan, which are within the ROI, PJM operates a capacity market designed to ensure that adequate resources are available to meet the demand for electricity into the future. The resources may include not only generating stations, but also demand response actions and energy efficiency measures by consumers to reduce their demand for electricity. Generally, demand response capacity is created when an electricity consumer agrees to reduce load at PJM's request during narrowly defined peak demand

[8] PJM Interconnection is a regional transmission organization that manages the bulk power system and wholesale electricity markets for all of parts of Pennsylvania, Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Tennessee, Virginia, West Virginia, and the District of Columbia.

periods. Exelon Generation sells both generation and demand response capacities into the PJM wholesale capacity market in the ROI.

In 2010, the nation's electricity providers reported total peak-load reductions of 33,283 MWe as a result of DSM programs, a 5.1 percent increase from the reduction reported in 2009. This represents 3 percent of the total generating capacity of the nation. Reported DSM costs increased $0.56 billion, up 16 percent from the $3.6 billion reported in 2009. DSM costs can vary significantly from year to year because of business cycle fluctuations and regulatory changes. Because costs are reported as they occur, while program effects may appear in future years, DSM costs and effects may not always show a direct relationship. In the five years between 2007 and 2011, nominal DSM expenditures have increased at a 22 percent average annual growth rate nationally. During the same period, actual peak load reductions have grown at a 7.2 percent average annual rate, from 30,318 MWe to 38,439 MWe nationally. The divergence between the growth rates of load reduction and expenditures was driven in large measure by 2007-2008 expenditures, which were in response to higher overall energy prices (EIA 2013c).

At the regional level, PJM has reported that demand response is a fast-growing component of its wholesale capacity market. The PJM capacity auction held in 2012 for estimated 2015/2016 demand cleared over 14,000 MWe of demand response capacity (PJM 2012). Even so, PJM has recognized that, if demand response is allowed to saturate its market, reliability of the overall power supply could be jeopardized because, as more megawatts of resources that are only available during narrowly defined peak periods are committed, fewer megawatts of more broadly available resources will be committed (PJM 2010b).

The Energy Security and Climate Stewardship Platform endorsed by governors of several states within the ROI in 2007 acknowledged the value of energy efficiency and set the goal of meeting 2 percent of the Midwest's annual retail sales of electricity through energy efficiency improvements by 2015. In 2009, the programs in Iowa, Minnesota, and Wisconsin were capturing savings from energy efficiency of 0.7 percent annual retail energy sales. (ECW 2009). Two percent of the 2010 annual retail sales of the states in the ROI was approximately 11 terawatt-hours. This amount represents just over half of the total electricity produced by LSCS in 2010.

The information provided in the paragraphs above suggests that, while it could be possible for PJM to satisfy 2,327 MWe of peak load demand with demand response capacity in 2022, replacing LSCS's 2,327 MWe of baseload capacity would not be advisable. Furthermore, while it may be possible, it appears unlikely that energy efficiency will actually increase in the ROI enough by 2022 to replace 2,327 MWe of baseload capacity.

The DSM alternative would produce different impacts than other alternatives addressed in this Environmental Report. Unlike the discrete generation options, there would be no major generating facility construction and few ongoing operational impacts. However, the loss of LSCS baseload generating capacity could require construction of new transmission lines to ensure local system stability. The most significant effects would likely occur during installation or implementation of conservation measures, when old appliances may be replaced, building climate control systems retrofitted, or new control devices installed. In some cases, increases in efficiency may come from better management of existing control systems.

In conclusion, although DSM is an important tool for meeting projected electricity demand and the impacts from the DSM alternative are generally small, DSM does not fulfill the stated purpose and need for license renewal of nuclear power plants, which is to provide full-time baseload power generation capability. Demand response measures are already captured in state and regional load projections and additional energy efficiency measures would offset only a fraction of the baseload energy supply lost by the shutdown of LSCS. In addition, the purpose of the LSCS license renewal is to allow Exelon Generation to sell wholesale power generated by LSCS to meet future demand. For these reasons, Exelon Generation does not consider DSM to be a viable supply of replacement baseload electricity. Hence, DSM does not represent a reasonable alternative to renewal of the LSCS operating licenses.

Solar

Solar energy is intermittent, which causes fluctuations that can change power frequency and affect grid-reliability when solar energy is used to supply electricity to the transmission grid. PJM Interconnection grants new solar facilities a 38 percent capacity credit (PJM 2010a). Accordingly, to replace the LaSalle approximate annual average net baseload generating capacity of 2,327 MWe, assuming the PJM Interconnection current-day capacity credit for solar generation, approximately 5,510 MWe of new solar capability would be required ([new solar capability] x 0.38 = 2,327 MWe x 0.90).

Two solar generation technologies have emerged as possible candidates for centralized electricity generation; photovoltaic (PV) and concentrating solar power (CSP) systems. Solar PV systems are semiconductor devices that convert sunlight directly into electricity. CSP systems use the thermal energy of sunlight to generate electricity.

CSP plants concentrate sunlight onto a heat-transfer fluid, which is used to generate steam that drives a steam turbine. Cooling towers or once-through cooling would be used to condense the spent steam back to water for reuse. CSP systems can provide baseload capacity without external balancing systems because their designs incorporate integral thermal energy storage to shift generation to periods without the solar resource and to provide backup energy during periods of reduced sunlight caused by cloud cover. The storage medium is typically a molten salt, which has extremely high storage efficiencies in demonstration systems. Current designs provide a maximum thermal energy storage of eight hours (NREL 2010c). However, CSP is designed to use only direct exposure so needs to face directly into the sun and track incident radiation.

Unlike CSP systems, PV generation does not provide all of the characteristics necessary for stable grid operation. PVs take advantage of direct and indirect (diffuse) exposure to sunlight therefore provides the most electricity during midday on sunny days, but none during evenings or at night (NREL 2010d). PV output can increase and fall rapidly during cloudy weather, making it difficult to maintain balance on a grid with a large penetration of PV (NREL 2010d). Therefore, the use of a PV system would require backup generation or another external balancing system, such as those described in Section 7.2.1.

Because CSP plants rely on sunlight for energy, the Midwestern climate with its moderate cloud cover makes these systems incapable of providing baseload power for the region. PV plants are capable of producing power from diffuse exposure to sunlight, however because they lack an energy storage capability, they cannot provide power except during the daylight hours. For these reasons, Exelon Generation does not consider solar alone as a reasonable alternative to LSCS license renewal.

Hydropower

About 1,434 MWe of utility generating capacity in the ROI is hydroelectric (EIA 2014). As the GEIS (NRC 2013b) points out in Section 2.3.3.1, large hydroelectric facilities have become difficult to site as a result of public concern over flooding, destruction of natural habitat, and alteration of natural river courses. Forty-eight hydropower projects, totaling 958 MWe, the largest of which is 214 MWe, are being considered in the ROI (FERC 2012). These small hydropower projects could not replace the 2,327 MWe generated at LSCS. DOE estimates there to be 2,131 MWe of small hydro- or low-power capacity spread over 11,881 different sites throughout the ROI (EERE 2006). Some of this additional water power resource potential would be gained from efficiency upgrades to existing hydroelectric facilities and new low-impact facilities (DOE 2011).

However, Exelon Generation has concluded that due to the large number of sites required and a total feasible capacity less than the energy supply that would be lost by the loss of LSCS, small site hydropower is not a reasonable alternative to LSCS license renewal.

The 1996 GEIS estimates land use of 4,000 km^2 (1,545 mi^2) per 1,000 MWe for hydroelectric power (NRC 1996c). Based on this estimate, replacement of LSCS generating capacity would require flooding approximately 9,310 km^2 (3,590 mi^2), resulting in a large land use impact. Further, operation of a hydroelectric facility would alter aquatic habitats upstream and downstream of the dam, which would affect aquatic communities. The Department of Energy has concluded that there are no remaining sites in the ROI that would be feasible for a large hydroelectric facility (EERE 2006).

Exelon Generation has concluded that, due to the lack of suitable sites in the ROI for a large hydroelectric facility and the amount of land needed (approximately 9,310 km^2 [3,590 mi^2]), large site hydropower is not a reasonable alternative to LSCS license renewal.

Geothermal

Geothermal energy is a proven resource for power generation. Geothermal power plants use naturally heated water as an energy source for electricity production. To produce electric power, underground high temperature reservoirs of steam or hot water are tapped by wells and the steam rotates turbines that generate electricity. Typically, water is then returned to the ground to recharge the reservoir.

Geothermal energy can achieve average capacity factors of 90 percent and can be used for baseload power where this type of energy source is available (MIT 2006). Widespread application of geothermal energy is constrained by the geographic availability of the resource (NREL 2012). In the U.S. high-temperature hydrothermal reservoirs are in the western continental states, Alaska, and Hawaii. There are no known high-temperature geothermal sites in the ROI (NREL 2011c, NREL 2011d). The ROI has low- to moderate-temperature resources that can be tapped for direct heat or geothermal heat pumps, but electricity generation is not feasible with these resources (NREL 2011c, NREL 2011d).

Exelon Generation has concluded that, due to the lack of high temperature geothermal sites in the ROI, geothermal power is not a reasonable alternative to LSCS license renewal.

Tidal, Ocean Thermal, and Wave

Technologies to harness electrical power from the ocean are tidal power, ocean thermal energy, and wave power conversion. These technologies are still in the early stages of development and are not commercially available to replace a large baseload generator such as LaSalle. Furthermore, the ROI consists of non-coastal states which, despite having Great Lake shorelines, lack tidal, ocean thermal, or wave power resources.

Tidal power technologies extract energy from the diurnal flow of tidal currents caused by the gravitational pull of the moon. Unlike wind and solar power, tidal streams offer an entirely predictable output. All coastal areas consistently experience two high tides and two low tides over a period of approximately 25 hours. However, because the lunar cycle is longer than 24 hours, the peak output differs by about an hour each day, and so tidal energy cannot be guaranteed at times of peak demand (Feller 2003).

Tidal power technologies consist of tidal turbines and barrages. Tidal turbines are similar in appearance to wind turbines and are mounted on the seabed. They are designed to exploit the higher energy density, but lower velocity, of tidal flows compared to wind. Tidal barrages are similar to hydropower dams in that they are dams with gates and turbines installed along the dam. When the tides produce an adequate difference in the level of the water on opposite sides of the dam, the gates are opened and water is forced through turbines, which turns a generator. For those tidal differences to be harnessed into electricity, the difference in water height between the high and low tides must be at least 5 m (16 ft). There are only about 20 sites on Earth with tidal ranges of this magnitude (EERE 2009). The only sites with adequate tidal differences within the U.S. are in Maine and Alaska (CEC 2011).

Ocean thermal energy conversion (OTEC) technology capitalizes on the fact that water temperature decreases with depth. If the temperature between the warm surface water and the cold deep water differs by about 20°C (36°F), an OTEC system can produce a significant amount of power. The temperature gradient in the Great Lakes is less than 18°C (32°F) and not a good resource for OTEC technology (EERE 2009).

Wave energy conversion takes advantage of the kinetic energy in the ocean waves (which are caused primarily by interaction of wind and the ocean surface). Wave energy offers an irregular, oscillatory, low frequency energy that must be converted to a 60-Hertz frequency before it can be added to the power grid (CEC 2011). Wave energy resources are best between 30 and 60 degrees latitude in both hemispheres and the potential tends to be greatest on western coasts (RNP 2007).

Offshore technologies that harness the energy of ocean waves and current have not been used at utility scale (NREL 2008b). Since the late 1990s, new technologies have been introduced to capture the energy of the ocean's waves, currents, and tides. Nearly 100 companies worldwide struggle to deploy their first prototypes and not all can be funded from the public sector. A viable strategy to help mature the marine renewable energy industry does not exist (NREL 2008b). Hence, although some technologies may be available in the future, none has yet been demonstrated to be capable of providing the electrical generating capacity needed to replace LSCS's baseload generating capacity.

Exelon Generation believes that tidal, ocean thermal, and wave technologies have not matured sufficiently to provide a viable supply of replacement baseload electricity for LSCS. As a result, Exelon Generation has concluded that, due to the lack of tidal, thermal, and wave resources in the ROI, and production limitations, these technologies are not reasonable alternatives to LSCS license renewal.

Wood Energy

The use of wood waste to generate electricity is largely limited to those states with significant wood resources. The pulp, paper, and paperboard industries in states with adequate wood resources generate electric power by consuming wood and wood waste for energy, benefiting from the use of waste materials that could otherwise represent a disposal problem. It takes roughly 1 ton per hour of wood waste to produce 1 MWe of electricity. Generally, the largest wood waste power plants are 40 to 50 MWe in size.

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

While some wood resources (forest, mill and urban wood residues) are available in the ROI, particularly in Illinois and Iowa (NREL 2005), Exelon Generation believes that, due to the lack of an environmental advantage, low heat content, handling difficulties, and high transportation costs, wood energy cannot provide a viable supply of replacement baseload electricity for LSCS. Hence, Exelon Generation has concluded that wood energy is not a reasonable alternative to LSCS license renewal.

Municipal Solid Waste

The decision to burn municipal solid waste to generate energy is usually driven by the need for an alternative to landfills, rather than by energy considerations. The use of landfills as a waste disposal option is likely to increase in the near term; however, it is unlikely that many landfills will begin converting waste to energy because of unfavorable economics. Estimates in the GEIS suggest that the overall level of construction impacts from a waste-fired plant should be approximately the same as that for a coal-fired plant. Additionally, waste-fired plants have the same or greater operational impacts (including impacts on the aquatic environment, air, and waste disposal) as coal-fired plants, and overall impacts would be larger than the environmental effects of LSCS license renewal.

Exelon Generation believes that, due to the high costs and lack of environmental advantages, burning municipal solid waste to generate electricity cannot provide a viable supply of replacement baseload electricity for LSCS. Hence, Exelon Generation has concluded that burning municipal solid waste is not a reasonable alternative to LSCS license renewal.

Other Biomass-Derived Fuels

In addition to wood and municipal solid waste fuels, there are several other concepts for fueling electric generators, including burning energy crops, converting crops to a liquid fuel such as ethanol, and gasifying energy crops (including wood waste). Power plants that employ direct combustion to convert biomass-derived fuels into electricity are commercially available. However, these biomass power plants are generally less than 50 MWe in size. Biomass gas turbine systems that use low-heat-value biogas from an anaerobic digester or a biomass gasifier are in the initial stages of commercialization. None of these biogas turbine technologies has progressed to the point of providing utility-scale electricity generating capacity to replace a baseload plant such as LSCS (EPA 2007).

Further, estimates in the GEIS suggest that the overall level of construction impacts from a crop-fired plant should be approximately the same as that for a wood-fired plant. Additionally, crop-fired plants would have similar operational impacts (including impacts on the aquatic environment and air). These systems also have large impacts on land use, due to the acreage needed to grow energy crops (NREL 2005).

Exelon Generation believes that, due to the high costs and lack of environmental advantage, burning other biomass-derived fuels to generate electricity cannot provide a viable supply of replacement baseload electricity for LSCS. Hence Exelon Generation has concluded that burning other biomass-derived fuels is not a reasonable alternative to LSCS license renewal.

Petroleum

The ROI has several petroleum (oil)-fired power plants; however, they produce less than 1 percent of the total power generated in the region (EIA 2014). From 2005 to 2010, the nation's energy sector has reduced the proportion of power produced by oil-fired generating plants by 64 percent (EIA 2014). Oil-fired operation is more costly than nuclear or coal-fired operation (IER 2012), and future increases in petroleum prices are expected to make oil-fired generation increasingly more costly. Also, construction and operation of an oil-fired plant would have significant environmental impacts (including impacts on the aquatic environment and air), comparable to those from a coal-fired plant.

Exelon Generation has concluded that, due to the high costs and lack of obvious environmental advantage, burning oil to generate electricity is not a reasonable alternative to LSCS license renewal.

Fuel Cells

Fuel cell power plants are in the initial stages of commercialization. While the number of stationary fuel cell shipments increased from about 2,000 in 2008 to 25,000 in 2012, the majority of these units are backup power or residential applications (EERE 2013). The largest stationary fuel cell power plant ever built is the 59 MWe Gyeonggi Green energy fuel cell park in South Korea, consisting of 21 units rated at 2.8 MWe each (FCE 2014). . The largest fuel cell power plant built in North America, the Dominion Bridgeport Fuel Cell plant in Bridgeport, CT, includes five units totaling 14.9 MWe (FCE 2013). However, stationary fuel cell plants typically generate much less (1 MWe or less) power (EERE 2013).

Exelon Generation believes that fuel cell technology has not matured sufficiently to provide a viable supply of replacement baseload electricity for LSCS. As a result, Exelon Generation has concluded that, due to cost and production limitations, fuel cell technology is not a reasonable alternative to LSCS license renewal.

Next Generation Nuclear Power

The Next Generation Nuclear Plant (NGNP) project was established under the Energy Policy Act in August 2005 (EPACT-2005). EPACT-2005 provided incentives in the form of tax credits and loan guarantees for new or significantly improved energy technologies, including the NGNP which established an overall plan and timetable for two phases of research, design, licensing, construction and operation activities leading to full implementation of the NGNP project by the end of FY 2021. At the time that EPACT-2005 was passed, it was envisioned that high-temperature gas-cooled nuclear reactor technology capable of generating electricity, producing hydrogen, or both, would be developed by the NGNP project (DOE 2010).

In 2011, the DOE Nuclear Energy Advisory Committee (NEAC) reviewed the readiness of the NGNP project to move from Phase I to Phase II, and concluded that the project was ready to proceed with some but not all aspects of Phase II (NEAC 2011). Considering the NEAC's conclusion about the NGNP project's readiness, Exelon Generation deems it unlikely that full implementation of the NGNP project will occur by FY 2021, and that a commercially viable replacement for LSCS using NGNP technology could not be sited, planned, licensed, constructed, and brought online by the time the existing LSCS operating licenses expire in 2022 and 2023.

Delayed Retirement

As the NRC noted in the GEIS, extending the lives of existing non-nuclear generating plants beyond the time they were originally scheduled to be retired represents another potential alternative to license renewal. In 2011 and 2012, Exelon Generation retired four fossil-fuel-fired generating units: Cromby Generating Station (Cromby) Units 1 (144 MW coal) and 2 (201 MW gas/oil) and Eddystone Generating Station (Eddystone) Units 1 (279 MW coal) and 2 (309 MW coal). These retirements involved fossil-fuel-fired units whose extended operation would be inconsistent with Exelon Corporation's strategy of offering more low−carbon electricity in the marketplace (Exelon 2012). Regardless, these units are not located within the ROI, and even if they continued to operate, the combined total generating capacity of 933 MWe would not replace the 2,327 MWe generated at LSCS.

Emerging EPA regulations on air quality, water use, and ash disposal will likely require existing non-nuclear generating units to choose between installing expensive control equipment and retirement. The Brattle Group's report, "Potential Coal Plant Retirements under Emerging Environmental Regulations" estimates that 50 to 65 GW of coal capacity will be at risk for retirement by 2020; and approximately 6 to 11 percent and 11 to 14 percent of the existing total regional capacity for PJM and Midwest ISO, respectively (Brattle Group 2010). For these reasons, Exelon Generation does not consider the delayed retirement of non-nuclear generating units to be a reasonable alternative to LSCS license renewal.

7.2.2 Environmental Impacts of Alternatives

This section evaluates the environmental impacts of alternatives that Exelon Generation has determined to be reasonable alternatives to LSCS license renewal: gas-fired generation, coal-fired generation, purchased power, new nuclear generation, wind energy, and combination alternatives.

7.2.2.1 Gas-Fired Generation

The NRC evaluated environmental impacts from gas-fired generation alternatives in the GEIS, including combined-cycle plants. Section 7.2.1.1 presents Exelon Generation's reasons for defining the gas-fired generation alternative as a six-unit combined-cycle plant on an existing power plant site. Construction of a gas-fired unit would have impacts on land-use and could impact ecological, aesthetic, and cultural resources. Human health effects associated with air emissions would be of some concern.

Air Quality

Natural gas is a relatively clean-burning fossil fuel that primarily emits oxides of nitrogen (NO_x), a regulated pollutant, during combustion. A natural-gas-fired plant would also emit small quantities of sulfur oxides presented as sulfur dioxide (SO_2), particulate matter (PM), and carbon monoxide (CO), all of which are regulated pollutants. In addition, a natural-gas-fired plant would produce CO_2, a greenhouse gas.

Control technology for gas-fired turbines focuses on NO_x emissions. Using data published by the EIA (EIA 2011) and the EPA (EPA 2000) the natural-gas-fired alternative emissions are calculated to be as follows (Tetra Tech 2013b):

SO_2 = 32 metric tons (36 tons) per year

NO_x = 536 metric tons (591 tons) per year

CO = 111 metric tons (123 tons) per year

Filterable Particulates = 93 metric tons (103 tons) per year (all particulates are particulates with diameters of 2.5 microns or less [$PM_{2.5}$])

CO_2 = 5,409,000 metric tons (5,963,000 tons) per year

The acid rain requirements of the 1990 CAA amendments capped the nation's SO_2 emissions from power plants. Each company with fossil-fuel-fired units was allocated SO_2 allowances. To be in compliance with the CAA, the companies must hold enough allowances to cover their annual SO_2 emissions. Exelon Generation would need to obtain SO_2 credits to operate a fossil-fuel-fired plant. In 1998, the EPA promulgated the NO_x SIP Call regulation that required 22 states, including all the states in the ROI except Iowa, to reduce their NO_x emissions by more than 30 percent to address the dispersion of ground-level ozone across state lines (EPA 1998b).

In July 2011, EPA published the Cross-State Air Pollution Rule (CSAPR) which requires states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. CSAPR was intended to replace the 2005 Clean Air Interstate Rule (CAIR) which was remanded to EPA by the US Court of Appeals for the DC Circuit in 2008. CSPAR requires all of the states in the ROI to reduce annual SO_2 emissions, annual NO_x emissions, and ozone-season NO_x emissions to assist in attaining the 1997 ozone and fine particle and 2006 fine particle NAAQS. The CSAPR allows air-quality-assured allowance trading among covered sources based on existing, successful allowance trading programs (EPA Undated). In August 2012, the US Court of Appeals for the DC Circuit vacated CSAPR and ordered EPA to continue to administer CAIR while it works on a replacement transport rule. CAIR addresses interstate pollution by capping annual NO_x and SO_2 emissions from applicable electric generating units in 27 states, including Illinois, and the District of Columbia. The states allocate CAIR NO_x allowances. Hence, to operate a new fossil-fuel-fired plant, Exelon Generation would need to obtain enough NO_x credits and SO_2 allowances to cover annual emissions. Additionally, because the Chicago and St. Louis areas are nonattainment areas (having air quality worse than the NAAQS) for ozone, a fossil-fuel-fired plant would potentially need to obtain NO_x emission reduction credits in the amount of 1.0 metric tons (1.1 tons) of NO_x for every ton of NO_x emitted (Evolution Markets 2014).

The EPA issued the Mandatory Reporting of Greenhouse Gases Rule in December 2009 that requires reporting of greenhouse gas data and other relevant information from large sources and suppliers in the U.S. The purpose of the rule is to collect accurate and timely greenhouse gas data to inform future policy decisions. In December 2010, the EPA issued a series of rules that put the necessary regulatory framework in place to ensure that industrial facilities can get CAA permits covering their greenhouse gas emissions when needed. (EPA 2012)

NO_x effects on ozone levels, SO_2 allowances, NO_x credits, and CO_2 permitting could all be issues of concern for gas-fired combustion. While gas-fired turbine emissions are less than coal-fired boiler emissions, the emissions are still substantial. Exelon Generation concludes that emissions from the gas-fired alternative would noticeably alter local air quality, but would not cause or contribute to violations of NAAQS in the region. Based on these emissions, Exelon Generation believes human health impacts would be SMALL to MODERATE. Air quality impacts would be MODERATE.

Waste Management

The solid waste generated from this type of facility would be minimal. The only noteworthy waste would be a small amount of spent catalyst from the spent selective catalytic reduction (SCR) process used for NO_x control (NRC 2011b). Exelon Generation concludes that gas-fired generation waste management impacts would be SMALL.

Water Resources

Cooling water requirements for combined cycle gas-fired plants are less than those for nuclear plants. A closed-cycle cooling system such as cooling towers would be used. Impacts to aquatic resources and water quality from a gas-fired plant's cooling water withdrawals from and discharges to a surface water source would likely be smaller than the impacts of LSCS on the Illinois River. Potential impacts would be mitigated by permit requirements. Exelon Generation concludes that gas-fired generation impacts to aquatic resources and water quality would be SMALL.

Other Impacts

Construction of the gas-fired alternative on an existing plant site would affect the site and the associated utility corridors. New gas pipelines to the gas turbines would likely be required in this alternative. To the extent practical, Exelon Generation would route the pipelines along existing, previously disturbed rights-of-way (ROW) to minimize impacts. Two new pipelines, each approximately 41 cm (16 in) in diameter, would require a 30.5-m (100-ft) wide ROW. The new construction could also necessitate an upgrade of the statewide natural gas pipeline network. Exelon Generation estimates that 38 ha (94 ac) would be needed for a gas-fired plant, but the location on an existing plant site would minimize additional impacts. Therefore, land use impacts would be SMALL. Erosion and sedimentation, fugitive dust, and construction debris impacts would be noticeable, but minor and temporary with appropriate controls. Compliance with applicable state and federal endangered species protection laws would minimize adverse effects on threatened or endangered species, ensuring a NOT LIKELY TO ADVERSELY AFFECT impact. The potential loss of terrestrial habitat would be mitigated by location on an existing site, thus the impact to terrestrial ecological resources would be SMALL. Depending on the state hosting the new gas-fired alternative, impacts to cultural resources could be possible because not all states require the protection of cultural resources on private lands. Therefore, impacts to cultural resources may be NOT PRESENT to could ADVERSELY AFFECT. Exelon Generation estimates a temporary peak construction workforce of 1,783; thus, socioeconomic impacts of construction would be SMALL. However, Exelon Generation estimates a significantly reduced workforce of 94 for gas-fired plant operations, and the loss of approximately 910 jobs at LSCS, which would cease operations, resulting in adverse socioeconomic impacts. Loss of the nuclear facility workforce would affect various aspects of the local community including employment, taxes, housing, off-site land use, economic structure, and public services in the vicinity of LSCS. Exelon Generation believes these, mostly adverse, impacts would be MODERATE.

Visual impacts would be consistent with the industrial nature of the selected site. The stacks of the new gas-fired units may add visual impacts at the existing power plant site where they are constructed; but these should be minimal because of the presence of existing plant structures. Noise levels at the existing power plant site would not change perceptibly due to the addition of gas-fired units. Hence, the impact on aesthetic resources would be SMALL.

7.2.2.2 Coal-Fired Generation

The NRC evaluated environmental impacts from coal-fired generation alternatives in the GEIS and concluded that construction impacts could be substantial, due in part to the large land area required (which can result in the loss of natural habitat) and the large workforce needed. The NRC identified the major adverse impacts from operations as human health concerns associated with air emissions, waste generation, and losses of aquatic biota due to cooling water withdrawals and discharges.

The coal-fired alternative that Exelon Generation has defined in Section 7.2.1.1 would be located at an existing power plant site.

<u>Air Quality</u>

A coal-fired plant would emit SO_x, NO_x, PM, mercury, and CO, all of which are regulated pollutants. A coal-fired plant would also emit CO_2, which is a greenhouse gas. As Section 7.2.1.1 indicates, Exelon Generation has assumed a plant design that would minimize air emissions through a combination of boiler technology and post combustion pollutant removal. Using data published by the Energy Information Administration (EIA 2011) and the EPA (EPA 1998a; EPA 2010) the coal-fired alternative emissions are calculated to be as follows (Tetra Tech 2013b):

SO_x = 5,210 metric tons (5,750 tons) per year

NO_x = 1,490 metric tons (1,640 tons) per year

CO = 2,070 metric tons (2,280 tons) per year

Mercury = 0.12 metric tons (0.14 tons) per year

PM:

PM_{10} (particulates having a diameter of greater than 2.5 microns to 10 microns) = 56 metric tons (61 tons) per year

$PM_{2.5}$ (particulates having a diameter 2.5 microns or less) = 15 metric tons (16 tons) per year

CO_2 = 19,900,000 metric tons (21,933,000 tons) per year

The discussion in Section 7.2.2.1 of regional air quality is applicable to the coal-fired generation alternative. The NRC also identified global warming and acid rain as potential impacts. In February 2012, the EPA finalized Mercury and Air Toxics Standards to limit mercury, acid gases, and other toxic pollution from power plants. In July 2012, the EPA finalized the Greenhouse Gas Tailoring Rule which requires the use of the best available control technology for greenhouse gas emissions from major industrial facilities, including power plants. Exelon Generation concludes that federal legislation and large-scale effects, such as global warming, acid rain, and mercury emissions are indications of concerns about the destabilization of important air resources resulting from use of coal as a boiler fuel. SO_x emission allowances, NO_x credits, low NO_x burners, over-fire air, fabric filters or electrostatic precipitators, and scrubbers are mitigation measures imposed by regulation. As such, Exelon Generation concludes that the coal-fired alternative would have MODERATE impacts on air quality; the impacts would be noticeable and greater than those of the gas-fired alternative, but would not destabilize air quality in the area. The impacts on human health would likewise be MODERATE.

Waste Management

Exelon Generation concurs with the GEIS assessment that the coal-fired alternative would generate substantial solid waste. The coal-fired plant would annually consume approximately 8,273,000 metric tons (9,120,000 tons) of coal having an ash content of 5.9 percent (Tetra Tech 2013b). In 2011, Exelon Power reused 92 percent, or more than 418,000 metric tons (461,000 tons), of its coal combustion and scrubber byproducts in beneficial applications. Exelon Power's beneficial reuse continued to far outpace the national recycling rate of approximately 45 percent for these types of materials (Exelon 2011c). After combustion, approximately 446,000 metric tons (491,000 tons) per year of ash would be marketed for beneficial reuse. The remaining ash, approximately 38,700 metric tons per year (42,700 tons per year), would be collected and disposed of on-site, if space were available. In addition, approximately 203,600 metric tons (224,400 tons) of scrubber sludge per year would be marketed for beneficial reuse. The remaining sludge, approximately 17,700 metric tons (19,500 tons) would be disposed of on-site each year (based on annual limestone usage of about 185,900 metric tons or 205,000 tons). Exelon Generation estimates that ash and scrubber waste disposal over a 20-year period would require approximately 7.7 ha (19 ac). If this acreage is not available at the power plant site where the new coal-fired unit would be sited, off-site disposal would necessary, which would increase disposal impacts.

Exelon Generation believes that proper siting, current waste management practices, and current waste monitoring practices would prevent waste disposal from destabilizing any resources. After closure of the waste site and revegetation, the land would be available for other uses. For these reasons, Exelon Generation believes that waste disposal for the coal-fired alternative would have SMALL impacts.

Water Resources

Cooling water requirements for coal-fired plants are similar to those for nuclear plants having similar generating capacity. A closed cycle cooling system such as cooling towers would be used. Impacts to aquatic resources and water quality from a coal-fired plant's cooling water withdrawals from and discharges to a surface water source would likely be similar to the impacts of LSCS on the Illinois River. Impacts would be mitigated by permit requirements. Exelon Generation concludes that impacts of coal-fired generation on aquatic resources and water quality would be SMALL.

Other Impacts

Exelon Generation estimates that construction of the power block and coal storage area would affect 154 ha (382 ac) of land and associated terrestrial habitat. Exelon Generation has assumed that much of this construction would be on previously disturbed land at an existing power plant site. Hence, land use impacts would be SMALL to MODERATE. Installation of a new rail spur or expansion of an existing spur would likely be required for coal and limestone deliveries under this alternative. As with any large construction project, some erosion and sedimentation and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. Debris from clearing and grubbing could be disposed of on-site. Waste disposal would require 7.7 ha (19 ac). Impacts to ecological resources would be consistent with impacts to land use and therefore, could be SMALL to MODERATE. Compliance with applicable state and federal endangered species protection laws would minimize any adverse impacts to threatened or endangered species, ensuring a NOT LIKELY

TO ADVERSELY AFFECT impact. Depending on the state hosting the new coal-fired alternative, cultural resources could be NOT PRESENT or impacts could ADVERSELY AFFECT cultural resources, because not all states require the protection of cultural resources on private lands. Exelon Generation estimates a temporary peak construction work force of 4,337 people. Socioeconomic impacts from the construction workforce would be SMALL if the construction site is near a large metropolitan area and worker relocation is not necessary. Exelon Generation estimates an operational workforce of 326 people for the coal-fired alternative. This is a sizable reduction in operating personnel compared to LSCS's approximately 910 personnel. Loss of a large portion of the nuclear facility workforce would impact various aspects of the local community near LSCS, including employment, taxes, housing, off-site land use, and public services. Thus, reduction in workforce would result in mostly adverse socioeconomic impacts characterized as MODERATE.

Visual impacts would be consistent with the industrial nature of the site. Cooling towers, stacks, boilers, and rail deliveries would change the visual nature of the site, but the impacts should be minimal because of the presence of existing plant structures. Noise levels at the existing power plant site would not change perceptibly due to the addition of coal-fired units. Thus, aesthetic impacts would be characterized as SMALL.

7.2.2.3 Purchased Power

As discussed in Section 7.2.1.2, Exelon Generation assumes that the generating technologies used under the purchased power alternative are the same as those that the NRC analyzed in the GEIS. Exelon Generation is adopting by reference the NRC analysis of the environmental impacts from those technologies. Under the purchased power alternative, therefore, environmental impacts would still occur, but they would originate from an existing power plant likely located elsewhere in the ROI.

Impacts would occur in areas where purchased power is produced and in the vicinity of LSCS. The magnitude of an impact would be proportional to the increased amount of power being produced at an existing plant. Incremental impacts from construction on air quality, waste management, water resources, and land use would be SMALL because Exelon Generation has assumed that enough excess capacity exists in PJM and Midwest ISO to allow purchase of replacement power without new construction.

Purchased power would result in an incremental positive socioeconomic impact in the vicinity of the existing plants and adverse socioeconomic impacts around LSCS from the loss of approximately 910 jobs at LSCS. Exelon Generation believes these adverse impacts would be MODERATE and would impact various aspects of local communities including employment, taxes, housing, off-site land use, and public services. The impact from existing plant operations to all other resources would be SMALL to MODERATE[9], depending on the type of fuel used, waste management practices, the locations of the existing plants, and the resource being considered.

Exelon Generation anticipates that additional transmission infrastructure would be needed in the event purchased power must replace LSCS capacity. From a local perspective, loss of LSCS capacity could require construction of new transmission lines to ensure local system stability, and impacts to land use and ecological resources from new transmission rights-of-way could be SMALL to MODERATE. Compliance with applicable state and federal endangered species protection laws would minimize adverse effects to threatened and endangered species,

[9] NOT LIKELY TO ADVERSELY AFFECT threatened and endangered species; NOT PRESENT or NO ADVERSE EFFECT to cultural resources.

ensuring a NOT LIKELY TO ADVERSELY EFFECT impact. Depending on the state hosting the new transmission infrastructure, impacts to cultural resources could be possible, because not all states require the protection of cultural resources on private lands. Therefore, cultural resources could be NOT PRESENT or impacts could ADVERSELY EFFECT cultural resources. From a regional perspective, PJM and Midwest ISO's interconnected transmission system is highly reliable.

7.2.2.4 New Nuclear Capacity

As discussed in Section 7.2.1.3, under the new nuclear capacity alternative, Exelon Generation would construct new nuclear generating units comparable in size to the LaSalle units using an NRC-certified standard design. Although Exelon Generation has not identified a location for a new nuclear plant near LSCS, Exelon Generation is assuming the new nuclear plant would be sited at an existing plant. Exelon Generation has reviewed the NRC early site permit analysis for new nuclear capacity at the Clinton Power Station site in DeWitt County, Illinois (NRC 2006), believes it to be sound, and notes that it addresses less capacity (2,200 MWe) than the approximate 2,327 MWe discussed in this analysis for LSCS. However, for comparison with LSCS license renewal, the Clinton analysis provides a conservative estimate of potential impacts.

Air Quality

Air quality impacts would be minimal. Air emissions, primarily from facility equipment (e.g., diesel generators, auxiliary boilers) and non-facility equipment (e.g., vehicular traffic), would be comparable to those associated with the continued operation of LSCS. Overall, such emissions and associated impacts are characterized as SMALL. Human health impacts would be comparable to those associated with continued operation of LSCS, which are characterized as SMALL.

Waste Management

Management of radioactive and nonradioactive wastes would be similar to that associated with the continued operation of LSCS. The overall impacts are characterized as SMALL.

Water Resources

Cooling water requirements would be similar to those of LSCS. A closed cycle cooling system such as cooling towers would be used. Impacts to aquatic resources and water quality from a new nuclear plant's cooling water withdrawals from and discharges to a surface water source would be similar to the impacts of LSCS on the Illinois River. Impacts would be mitigated by permit requirements. Exelon Generation concludes that nuclear generation's impacts to aquatic resources and water quality would be SMALL.

Other Impacts

Exelon Generation estimates that construction of the reactor units and auxiliary facilities would affect 104 ha (258 ac) of land and associated terrestrial habitat. Because much of this construction would be on previously disturbed land, impacts would be SMALL to MODERATE. Installation or expansion of either a new or existing rail spur or barge offloading facility would potentially be required for reactor vessel and other deliveries under this alternative. As with any large construction project, some erosion and sedimentation and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. Debris from clearing and grubbing could be disposed of on-site. Effects on ecological resources would be consistent with the impacts of construction on land use, and could be SMALL to MODERATE. Compliance with applicable state and federal endangered species protection laws would minimize any adverse effects to threatened or endangered species, ensuring a NOT LIKELY TO ADVERSELY AFFECT impact. Cultural resources protection would be implemented consistent with applicable state and federal requirements, ensuring NO ADVERSE EFFECT. Nuclear plants require an NRC license, therefore, consultation with the State Historic Preservation Officer is required by the National Historic Preservation Act (16 U.S.C. 470f) if construction or operation could result in adverse effects on a historic property.

Visual impacts would be consistent with the industrial nature of the site. Cooling towers and reactor containment buildings would change the visual nature of the site, but the impacts should be minimal because of the presence of existing plant structures. Noise levels at the existing power plant site would not change perceptibly due to the addition of new nuclear units. Thus aesthetic impacts would be SMALL.

Based on a review of recent Early Site Permit and Combined License (COL) applications, Exelon Generation estimates a temporary peak construction work force of approximately 4,282 workers. The surrounding communities would experience moderate demands on housing, public services, and transportation during construction, and would experience increased tax revenues. Socioeconomic impacts from construction would be minimal if the site is near a large metropolitan area and worker relocation was not required. Therefore, Exelon Generation concludes that socioeconomic impacts during construction would be SMALL to MODERATE, depending on the location of the plant. Exelon Generation estimates an operational workforce of 750 for the new nuclear alternative, based on recent applications. This is smaller than LSCS's workforce of approximately 910 personnel. Exelon Generation concludes that socioeconomic impacts during operation would be SMALL to MODERATE, depending on the location of the plant.

Exelon Generation estimates that other construction and operation impacts would be SMALL.

7.2.2.5 Wind Energy

As discussed in Section 7.2.1.4, between 4,270 MWe and 14,250 MWe of new wind capability could be required to replace LSCS's baseload generating capacity, depending on whether present or projected future capacity factors are applied. Each wind turbine would have a small footprint and would be tall (up to about 121 m [400 ft] to top of rotor tip) with large rotors (up to about 88-m [290-ft] rotor diameter) (NWW Undated), requiring an otherwise undisturbed airspace around it. Hence, development of wind energy projects to replace LSCS's capacity would require large commitments of land and, although land-based wind projects may be able to coexist with land uses such as farming, ranching, and forestry, wind energy development might not be compatible with land uses such as housing developments, airport approaches, some radar installations, and low-level military flight training routes (DOE 2008). Also, construction and operation of wind turbines could affect ecological, aesthetic, and cultural resources.

<u>Air Quality</u>

Potential benefits of using wind-generated electricity include reduction of fossil-fuel-generated levels of atmospheric CO_2, which is believed to be the major cause of global climate change (DOE 2008, page 13). In addition, compared with fossil-fueled generation, levels of regulated atmospheric pollutants such as nitrogen oxides, sulfur dioxide, and mercury, which can cause human health effects, would be reduced (DOE 2008). Hence, air quality impacts from wind generation would be SMALL. Any wind technology will result in emissions during operations because of fugitive dust and engine exhaust from on-site maintenance and repair activities and from commuter/delivery/support vehicles. These emissions would include a small amount of regulated pollutants (e.g., nitrogen oxides, sulfur dioxide, and mercury), volatile organic compounds, carbon dioxide, and hazardous air pollutants (BLM/DOE 2010). Such emissions would be intermittent and would have minor impacts on ambient air quality. Some air emissions from portable diesel generators would be comparable to or less than those associated with the continued operation of LSCS. Overall, pollutant emissions to air and associated impacts are characterized as SMALL. The impacts on human health would likewise be SMALL.

Waste Management

Minor quantities of construction-related wastes would be generated. During operation, maintenance activities could generate dielectric fluids at the wind turbine locations and substations. Overall, waste produced at wind generation facilities would be minimal, and associated impacts are characterized as SMALL.

Water Resources

Relatively very little water would be consumed during construction or operation of wind generation facilities, and no water would be diverted for condenser cooling. Impacts to water quality could occur from accidental spills of petroleum lubricants and fuel, but such impacts are expected to be minimal. Overall, impacts to water quality from wind generation facilities are characterized as SMALL.

Other Impacts

NREL (NREL 2009) reports that there is no uniformly accepted single metric of land use for wind power plants. However, two primary indices of land use do exist – the infrastructure/direct impact area (land temporarily or permanently disturbed by wind power plant development) and the total impact area (overall area of the power plant as a whole) (NREL 2009).

Permanent direct impact caused by road development, turbine pads and electrical support equipment averaged between 0 and 0.6 ha/MWe (1.5 ac/MWe) of capability, and temporary direct impact averaged between 0.1 and 1.3 ha/MWe (0.25 and 3.2 ac/MWe) of capability, for a combined direct impact area (both temporary and permanently disturbed land) of between 0.1 and 1.9 ha/MWe (0.25 and 4.7 ac/MWe) (NREL 2009).

The average value for the total area occupied by a land-based wind power plant is between 12 and 57 ha/MWe (30 and 141 ac/MWe) (NREL 2009). Using the lower end of the ranges of these estimates (to provide a conservative impacts comparison), new wind generating plants to replace the LSCS approximate annual average net baseload generating capacity of 2,327 MWe may have a total direct impact area ranging from 433 ha (1,070 ac) (based on estimated 2025 PJM capacity credit) to 1,440 ha (3,560 ac) (based on current PJM capacity credit). Meanwhile, the overall area occupied by such wind power plants may range from 51,720 ha (127,800 ac; based on estimated 2025 PJM capacity credit) to 172,400 ha (426,000 ac; based on current PJM capacity credit). Furthermore, it is unlikely that siting wind generation projects at existing power plant sites would reduce land use impacts. Overall, land use impacts from wind energy development are characterized as LARGE.

Development of land-based wind power projects may cause other direct and indirect environmental impacts that are predominately local, but can concern individuals in the affected communities and landscapes (DOE 2008). For example, indirect impacts can include trees being removed around turbines, and the presence of turbines causing some species or individuals to avoid previously viable habitats. Indirect habitat impacts on grassland species are a particular concern, because extensive wind energy development could take place in grassy regions of the country (DOE 2008). Direct impacts can include bird and bat mortality from exposure to the turbine blades or changes in air pressure near the turbine. This is a particular worry with bats because they are relatively long-lived mammals with low reproduction rates, which means that species populations could be adversely affected. Construction of wind farms would result in large land requirements for the construction of a transmission system to support the wind farms. Overall, the direct and indirect environmental impacts of wind energy development on ecological resources are characterized as SMALL to MODERATE.

Compliance with applicable state and federal endangered species protection laws would minimize any adverse impacts to threatened or endangered species, ensuring a NOT LIKELY TO ADVERSELY AFFECT impact. Depending on the state hosting the new wind-powered alternative, impacts to cultural resources could be possible, because not all states require the protection of cultural resources on private lands. Therefore, cultural resources could be NOT PRESENT or impacts could ADVERSELY AFFECT cultural resources.

Visual impacts would be considerable due to the number and size of wind turbines that would be required to provide between 4,270 MWe and 14,250 MWe of new wind capability, and because they would be prominent from afar in the open landscape and over a large area. Noise impacts would include aerodynamic noise from the blades moving through the air and mechanical sounds associated with the generator and gearbox (DOE 2008). Thus, aesthetic impacts are characterized as MODERATE to LARGE.

Socioeconomic impacts from the construction workforce could be significant, if worker relocation is required to sites located away from large metropolitan areas. Exelon Generation estimates a construction workforce of 980 and a permanent maintenance and operational workforce of 390 for the wind alternative; both estimates could be larger, depending on the selected wind capability requirement (DOE 2008). This is a sizable reduction in operating workforce from LSCS's approximately 910 personnel. Loss of jobs in the vicinity of LSCS would impact various aspects of the local community, usually adversely, including employment, taxes, housing, off-site land use, and public services, which could be significant. However, the communities and land-owners where the wind facilities would be located would receive royalties on land leases, property tax payments, and direct and indirect jobs, which would be a positive effect. Thus, the net socioeconomic impact is characterized as SMALL to MODERATE.

Offshore Facility Impacts

Offshore wind generation projects would create fewer land use conflicts than land-based wind projects, but the costs of offshore wind projects are higher than land-based projects by about 400 percent, which is attributed to the added complexity of siting wind turbines in an aquatic (and a potentially harsher) environment, larger foundation and infrastructure costs, and higher operations and maintenance costs because of accessibility issues and the harsh nature of the aquatic environment (EPA 2010). NREL's Regional Energy Deployment System model shows nationwide offshore wind potential penetration of between 54 GW and 89 GW by 2030, but only when economic scenarios favoring offshore wind are applied, including combinations of cost reductions (resulting from technology improvements and experience), rising natural gas prices (3 percent annually), heavy constraints on conventional power, and successful new transmission development in congested coastal regions, and national incentive policies including grants and favorable loan policies (NREL 2010b). Further, little information is available regarding other potential impacts of developing offshore wind generation plants in the Great Lakes, including impacts on aquatic and avian life, tourism, and commercial and recreational fishing. As a result, the Great Lakes Commission's Offshore Wind Workgroup has recommended sound planning and caution when moving forward with the development of offshore wind (GLWC 2009). While future development of wind generation in the ROI is likely to include both land-based and offshore wind farms, comparisons of LSCS license renewal impacts with offshore wind generation impacts is difficult. However, because LSCS license renewal involves no new construction, impacts from LSCS license renewal would be less than impacts from construction of a new offshore wind generation plant.

7.2.2.6 Wind Generation, PV Solar Generation and Gas-fired Combined-cycle Generation

Construction of the wind farm, solar generation, and gas-fired combined-cycle plants would have relatively larger environmental impacts in comparison to LSCS license renewal, which would involve no new construction activities. Operating impacts associated with the wind portion of this alternative are described in Sections 7.2.2.1.

The PV solar portion of this alternative would have the following impacts: Because PV generation facilities have no power block, potential impacts on ambient air quality associated with operation of a PV facility would be negligible (BLM/DOE 2010). Overall, air pollutant emissions from a PV facility are characterized as SMALL. The impacts on human health would be SMALL.

The operation of any solar power facility would generate industrial wastes, domestic wastes, and wastewaters in quantities similar to any industrial facility. The quantities of toxic wastes are expected to be small and would be managed in accordance with applicable environmental regulations (BLM/DOE 2010). PV solar cells contain small amounts of toxic metals such as cadmium, selenium, and arsenic. Under normal conditions, these metals are secured within sealed solar panels and represent no hazard to workers or the public. When removed from service, recycling opportunities would be sought, but if such opportunities are not available, discarded solar panels containing toxic metals would be characterized, and they might need to be managed as hazardous waste (BLM/DOE 2010). Overall, waste types and volumes produced at a solar power generation facility would be comparable to or less than those associated with the continued operation of LaSalle, and associated impacts are characterized as SMALL.

Operation of PV facilities would have minimal water consumption impacts because steam cooling is not needed. Impacts to water quality from a PV facility would be comparable to or less than those associated with continued operation of LaSalle. Overall, impacts on aquatic resources and water quality from PV facilities are characterized as SMALL.

Land requirements for solar plants are high. Estimates based on existing installations indicate that utility-scale plants would occupy about 1.6 ha (4.0 ac) per MWe for PV systems. Utility-scale solar plants have only been used in regions, such as the western United States, that receive high concentrations of solar radiation (5.24 to 7.65 kilowatt hours per square meter per day). Considering that the ROI receives only 3.25 to 4.56 kilowatt hours of solar radiation per square meter per day (NREL 2008a), Exelon Generation estimates that a utility-scale PV solar plant located in the ROI would occupy about 2.2 ha (5.4 ac) per MWe. The PJM Interconnection currently grants new solar facilities a 38 percent capacity credit (PJM 2010a). Accordingly, 2,700 MWe of PV solar energy capabilities would require 5,940 ha (14,580 ac). No existing power plant sites in the ROI are large enough to accommodate a PV solar facility of the generating capacity needed to replace the LaSalle baseload generation capacity. Accordingly, any solar plant constructed to replace LaSalle would have to be located on a greenfield site. Assuming that sufficient land could be acquired for a solar generation facility, development of the greenfield site would result in large land use impacts. Overall, land use impacts from PV solar energy development is characterized LARGE.

Much of the land area occupied by a PV generation facility would be cleared and maintained as an unvegetated or sparsely vegetated surface throughout the life of the facility. This would create an extensive loss of terrestrial habitat. Adjacent terrestrial communities could be affected by such factors as increased runoff, altered hydrology, sedimentation, reduced water quality, and erosion (BLM/DOE 2010). Habitat disturbance from the construction of a solar generation project could adversely affect wildlife, and the presence of the solar generation facilities would create a physical hazard to some wildlife. However, human activity, and the limited quantity and quality of habitat within the project site would discourage the presence of most wildlife in the immediate project area (BLM/DOE 2010). Overall, the direct and indirect environmental impacts on ecological resources of PV solar power projects are characterized as LARGE.

Compliance with applicable state and federal endangered species protection laws would minimize any adverse effects to threatened or endangered species, ensuring a NOT LIKELY TO ADVERSELY AFFECT impact. Depending on the state hosting the new solar energy alternative, cultural resources could be NOT PRESENT, or impacts could ADVERSELY AFFECT cultural resources because not all states require the protection of cultural resources on private lands.

Visual impacts would be considerable due to the number of PV panels that would be required to provide approximately 2,700 MWe of new solar capability. PV systems do not include highly reflective surfaces like other solar collectors; however, the panels and other components do reflect light that could result in glinting glare, and other visual effects that could be visible for long distances (BLM/DOE 2010). PV facility operations would have a minimal number of noise sources and low-level noises and would typically be inaudible or barely perceptible at the site boundaries. PV facilities would be operating during daytime only reducing the noise impacts. (BLM/DOE 2010) Thus, aesthetic impacts would be characterized as MODERATE to LARGE based on visual impacts and noise impacts would be SMALL.

Exelon Generation estimates an operational workforce of approximately 100, assuming a workforce of approximately 25 for a 1,457-ha (3,600 ac) facility (BLM/DOE 2010). This is a large reduction in personnel compared to LaSalle’s approximately 910 personnel. Loss of the nuclear plant workforce would affect various aspects of the local community in the vicinity of LaSalle, including employment, taxes, housing, off-site land use, and public services, and the effects could be significant and adverse. Thus, the net socioeconomic impact is characterized as SMALL to MODERATE.

Additional impacts from the backup gas-fired combined-cycle plants would be similar to those described in Section 7.2.2.1. As a whole, the combination of alternatives would have relatively greater impacts than from any of its three components. Furthermore, those impacts would also be greater than the impacts from renewal of the LSCS operating licenses.

Exelon Generation concludes that it is very unlikely that the environmental impacts of this or any combination of fossil-fuel-fired and renewable energy alternatives would result in impacts comparable to the small impacts associated with renewal of the LSCS operating licenses because most combination alternatives would require construction activities, and several would require large land commitments.

Table 7.2-1 Gas-Fired Alternative

Characteristic	Basis
Plant size = 2,400 MWe ISO rating net consisting of six 400-MWe combined-cycle units	Manufacturer's standard size gas-fired combined-cycle units (total rating approximately LSCS's annual net mean generation capacity of 2,327 MWe
Plant size = 2,502 MWe ISO rating gross	Based on 4 percent on-site power usage
Number of plants/combined-cycle units = 6 / 6	Assumed
Fuel Type = natural gas	Assumed
Fuel heating value = 1,009 Btu/ft^3	Typical for natural gas used in ROI (EIA 2011)
Fuel SO_2 emission = 0.00066 lb/million Btu	(EPA 2000)
NO_x control = selective catalytic reduction (SCR) with steam/water injection	Best available for minimizing NO_x emissions (EPA 2000)
Fuel NO_x emission = 0.0109 lb/million Btu	Typical for large SCR controlled gas fired units with water injection (EPA 2000)
Fuel CO emission = 0.00226 lb/million Btu	Typical for large SCR controlled gas fired units. (EPA 2000)
Fuel $PM_{2.5}$ emission = 0.0047 lb/million Btu	(EPA 2000)
Fuel CO_2 emission = 110 lb/million Btu	(EPA 2000)
Heat rate = 5,690 Btu/kWh	(GE Energy 2007)
Capacity factor = 87 percent	Assumed based on conservative performance of modern plants (EIA 2010b)

Note: The difference between "net" and "gross" is electricity consumed on-site.
The heat recovery steam generators (HRSGs) do not contribute to air emissions.

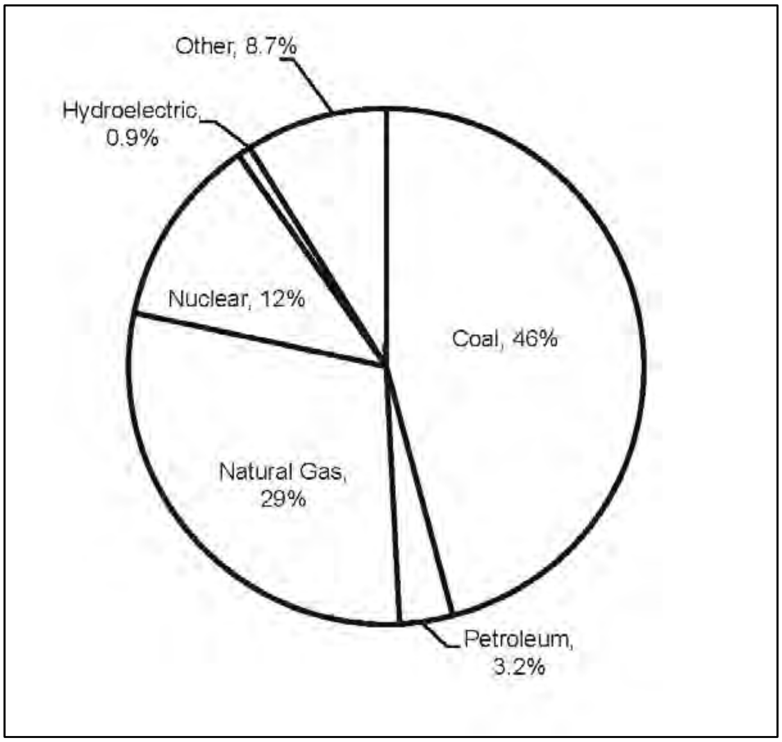
Btu = British thermal unit
ft^3 = cubic foot
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59 °F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
ROI = region of interest (Illinois, Indiana, Iowa, Michigan, Missouri, Wisconsin)
kWh = kilowatt hour
lb = pound
MWe = megawatt electrical
NO_x = nitrogen oxides
$PM_{2.5}$ = particulates having diameter of 2.5 microns or less
CO = carbon monoxide
CO_2 = carbon dioxide
SO_2 = sulfur dioxide

Table 7.2-2 Coal-Fired Alternative

Characteristic	Basis
Plant size = 2,400 MWe ISO rating net	Size set equal to gas-fired alternative (approximately LSCS's annual net mean generation capacity of 2,327 MWe)
Plant size = 2,552 MWe ISO rating gross	Based on 6 percent on-site power usage
Number of plants = 4	Assumed
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxides emissions (EPA 1998a)
Fuel Type = sub-bituminous, pulverized coal	Assumed
Fuel heating value = 9,315 Btu/lb	Typical for sub-bituminous coal used in ROI (EIA 2011)
Fuel ash content by weight = 5.86 percent	Typical for sub-bituminous coal used in ROI (EIA 2011)
Fuel sulfur content by weight = 0.72 percent	Typical for sub-bituminous coal used in ROI (EIA 2011)
Uncontrolled NO_x emission = 7.2 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (EPA 1998a)
Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry bottom, NSPS (EPA 1998a)
Uncontrolled CO_2 emission = 4,810 lb/ton	Typical for pulverized coal, tangentially fired, dry bottom, NSPS (EPA 1998a)
Uncontrolled SO_x emission = 25.2 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (EPA 1998a)
Uncontrolled PM_{10} emission = 13.5 lb/ton	Typical for pulverized coal, tangentially fired, dry bottom, NSPS (EPA 1998a)
Uncontrolled $PM_{2.5}$ emission = 3.52 lb/ton	Typical for pulverized coal, tangentially fired, dry bottom, NSPS (EPA 1998a)
Uncontrolled Hg emission = 0.000016 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (EPA 1998a)
Heat rate = 8,937 Btu/kWh	Typical for ultra-supercritical coal-fired boilers (S&L 2009)
Capacity factor = 0.85	Assumed based on conservative performance of modern plants (EIA 2010b)
NO_x control=low NO_x burners, over-fire air and selective catalytic reduction (95 percent reduction)	Best available and widely demonstrated for minimizing NO_x emissions (EPA 1998a)
Particulate control = baghouse fabric filters (99.9 percent removal efficiency)	Best available for minimizing particulate emissions ((EPA 1998a)
SO_x control = Wet scrubber - limestone (95 percent removal efficiency)	Best available for minimizing SO_x emissions (EPA 1998a)

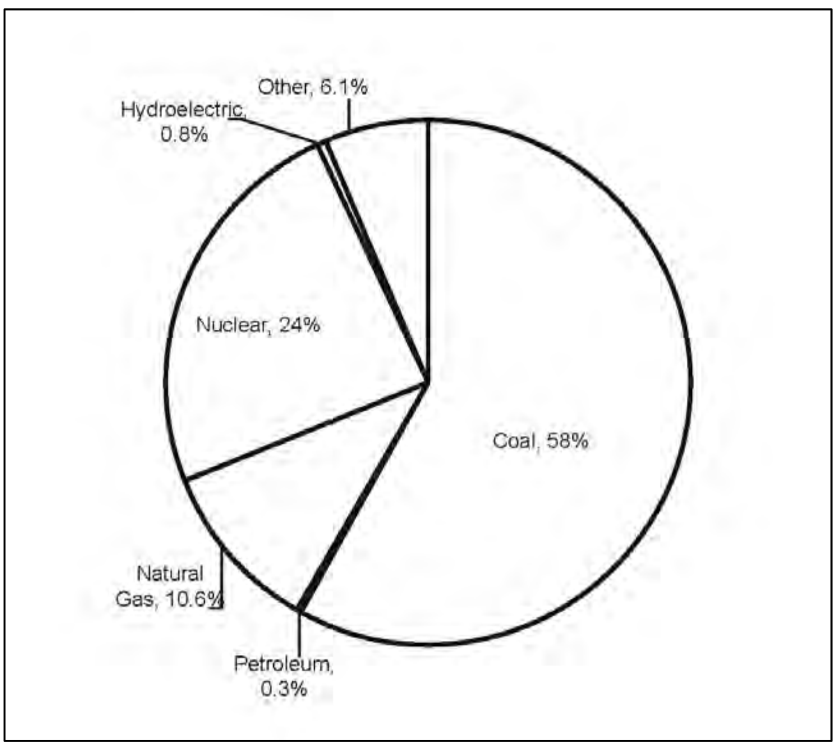
Table 7.2-2 Coal-Fired Alternative (Continued)

Note: The difference between "net" and "gross" is electricity consumed on-site.
The heat recovery steam generators (HRSGs) do not contribute to air emissions.
Btu = British thermal unit
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59 °F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
NSPS = New Source Performance Standard
ROI = region of interest (Illinois, Indiana, Iowa, Michigan, Missouri, Wisconsin)
Hg = mercury
lb = pound
SOx = sulfur oxides
kWh = kilowatt hour
MWe = megawatt electrical
NO_x = nitrogen oxides
$PM_{2.5}$ = particulates having diameter of 2.5 microns or less
PM_{10} = particulates having diameter of 10 microns or less
CO = carbon monoxide
CO_2 = carbon dioxide



(Source: Derived from State Tables 4, EIA 2014)

Figure 7.2-1 ROI Generating Capacity by Fuel Type 2012



(Source: Derived from State Tables 5, EIA 2014)

Figure 7.2-2 ROI Energy Output by Fuel Type 2012

Chapter 8

Comparison of Environmental Impact of License Renewal with the Alternatives

NRC

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

Chapter 4 analyzes environmental impacts of the LSCS license renewal and Chapter 7 analyzes impacts of reasonable alternatives. Table 8.0-1 summarizes environmental impacts of the proposed action (license renewal) and the reasonable alternatives, for comparison purposes. The environmental impacts compared in Table 8.0-1 are either Category 2 issues for the proposed action or are issues that the GEIS (NRC 2013b) identified as major considerations in an alternatives analysis. Therefore, although for example, the GEIS designates air quality impacts as a Category 1 issue, Table 8.0-1 includes a comparison of air impacts from the proposed action to those of the alternatives. Table 8.0-2 provides a more detailed comparison of the alternatives.

As shown in Table 8.0-1 and Table 8.0-2, environmental impacts of the proposed action (LSCS license renewal) to which the SMALL, MODERATE or LARGE measures of significance apply are all expected to be SMALL. For threatened and endangered species, the proposed action is not likely to adversely affect protected species, and for cultural resources, the proposed action would have no adverse effect. Exelon Generation expects that environmental impacts on specific resources from the alternative actions identified as reasonable could be SMALL to LARGE. For threatened and endangered species, the alternative actions are expected to have no effect or be not likely to adversely affect protected species. For cultural resources, the alternative actions could occur where no resource is present or in a location where an adverse effect on resources would take place.

Exelon Generation concludes that the environmental impacts of the continued operation of LSCS, providing approximately 2,327 MWe of base-load power generation through 2042, would be smaller overall than impacts associated with any of the other reasonable alternatives that are analyzed. LaSalle's continued operation would create the same or significantly less environmental impact than the construction and operation of any other new base-load generation capacity, and therefore, there is no other preferred alternative. Additionally, LSCS's continued operation would extend the existing significant positive economic impact on the communities near the Station. Therefore, Exelon Generation concludes that the results of this analysis support the approval of LSCS license renewal to maintain the option of continued LSCS operation for energy planning decision makers.

Table 8.0-1 Impacts Comparison Summary

Impact	Proposed Action (License Renewal)	Base (Decom-missioning)	With Gas-Fired Generation	With Coal-Fired Generation	With Purchased Power	With New Nuclear Capacity	With Wind Energy	With Combined Wind Energy, Solar Power, & Gas-Fired Generation
Land Use	SMALL	SMALL	SMALL	SMALL to MODERATE	SMALL to MODERATE	SMALL to MODERATE	LARGE	LARGE
Water Resources	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE	SMALL	SMALL	SMALL
Air Quality	SMALL	SMALL	MODERATE	MODERATE	SMALL to MODERATE	SMALL	SMALL	SMALL to MODERATE
Ecological Resources	SMALL	SMALL	SMALL	SMALL to MODERATE	SMALL to MODERATE	SMALL to MODERATE	SMALL to MODERATE	LARGE
Threatened or Endangered Species[1]	NOT LIKELY TO ADVERSELY AFFECT	Not an impact evaluated by Decommissioning GEIS (NRC 1996c)	NOT LIKELY TO ADVERSELY AFFECT	NOT LIKELY TO ADVERSELY AFFECT	NOT LIKELY TO ADVERSELY AFFECT	NOT LIKELY TO ADVERSELY AFFECT	NOT LIKELY TO ADVERSELY AFFECT	NOT LIKELY TO ADVERSELY AFFECT
Human Health	SMALL	SMALL	SMALL to MODERATE	MODERATE	SMALL to MODERATE	SMALL	SMALL	SMALL to MODERATE
Socioeconomics	SMALL	SMALL	SMALL to MODERATE	SMALL to MODERATE	MODERATE	SMALL to MODERATE	SMALL to MODERATE	SMALL to MODERATE
Waste Management	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE	SMALL	SMALL	SMALL

Table 8.0-1 Impacts Comparison Summary (continued)

Impact	Proposed Action (License Renewal)	Base (Decom-missioning)	With Gas-Fired Generation	With Coal-Fired Generation	With Purchased Power	With New Nuclear Capacity	With Wind Energy	With Combined Wind Energy, Solar Power, & Gas-Fired Generation
Aesthetics	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE	SMALL	MODERATE to LARGE	MODERATE to LARGE
Cultural Resources[2]	NO ADVERSE EFFECT	NO ADVERSE EFFECT	NOT PRESENT to ADVERSE EFFECT	NOT PRESENT to ADVERSE EFFECT	NOT PRESENT to ADVERSE EFFECT	NO ADVERSE EFFECT	NOT PRESENT to ADVERSE EFFECT	NOT PRESENT to ADVERSE EFFECT

[1] Effects on threatened or endangered species may be characterized as follows: (1) no effect, (2) not likely to affect, (3) likely to affect, (4) likely to jeopardize continued existence.
[2] Effects on historic properties may be characterized as follows: (1) no historic properties present, (2) historic properties are present, but not adversely affected, or (3) historic properties are adversely affected (from 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Footnote 3).

Table 8.0-2 Impacts Comparison Detail

Proposed Action (License Renewal)	Base (Decom-missioning)	With Gas-Fired Generation	With Coal-Fired Generation	With Purchased Power	With New Nuclear Capacity	With Wind Energy	With Combined Wind Energy, PV Solar Energy, & Gas-Fired Generation
Alternative Description							
Renewal of LSCS Units 1 and 2 licenses for 20 years each, followed by decommissioning	Decommissioning following expiration of current LSCS Units 1 and 2 licenses. Adopting by reference, as bounding for LSCS decommissioning GEIS description (Section 7.1)	New construction at an existing power plant site (Section 7.2.2.1)	New construction at an existing power plant site (Section 7.2.2.2)	Adopting by reference GEIS description of alternate technologies (Section 7.2.2.3)	New construction at an existing power plant site (Section 7.2.2.4)	Construction of wind energy turbine capacity (Section 7.2.2.5)	Construction of wind energy turbines, solar collectors, and gas-fired firming capacity (Section 7.2.2.7)
		Six pre-engineered 400-MWe gas-fired combined-cycle systems with heat recovery steam generators, producing combined total of 2,400 MWe (net); capacity factor: 0.87	Four 600-MWe (net) ultra-supercritical pulverized coal – fired boiler; capacity factor 0.85		Two units using an NRC-certified standard design producing combined 2,200 MWe net, capacity factor; 0.90	2011 capacity factor: 0.15 – 14,250 MWe wind turbine capacity; 2025 capacity factor: 0.49 – 4,270 MW wind turbine capacity; Assume no firming capacity	Wind turbine – 2,200 MWe (capacity factor: 0.49), plus firming capacity of 130 MWe from gas-fired combined cycle generation and Solar – 2,700 MWe (capacity factor: 0.38), plus firming capacity of 270 MWe from gas-fired combined cycle generation
		Construct two 41-cm (16 in) diameter gas pipelines in an existing 100-ft wide ROW. May require upgrades to existing pipelines	Construct new rail spur or extend an existing spur	Construct new transmission lines to assure local transmission system stability	Construct new rail spur or extend an existing spur or barge offloading facility	Construct new transmission lines	Construct new transmission lines

Table 8.0-2 Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decom-missioning)	With Gas-Fired Generation	With Coal-Fired Generation	With Purchased Power	With New Nuclear Capacity	With Wind Energy	With Combined Wind Energy, PV Solar Energy, & Gas-Fired Generation
		Construct intake/discharge system	Construct cooling tower(s) and intake/ discharge system		Construct cooling tower(s) and intake /discharge system		
		Natural gas, 1,009 Btu/ft^3; 5,690 Btu/kWh; 0.00066 lb SO_2/million Btu; 0.0109 lb NO_x/million Btu; 1.07 x 10^{11} ft^3 gas/yr	Pulverized sub-bituminous coal, 9,315 Btu/lb; 8,937 Btu/kWh; 5.9% ash; 0.72% sulfur; 7.2 lb NO_x/ton coal; 9.12 x 10^6 tons coal/yr		Low-enriched uranium fuel; refueling every 18 months		Same natural gas fuel characteristics as for the Gas-Fired Generation alternative.
		Selective catalytic reduction with steam/water injection	Low NO_x burners, overfire air and selective catalytic reduction (95% NO_x reduction efficiency) Wet scrubber – limestone desulfurization system (95% SOx removal efficiency); 2.05 x 105 tons limestone/yr; Fabric filters (99.9% particulate removal efficiency)				

Table 8.0-2 Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decom-missioning)	With Gas-Fired Generation	With Coal-Fired Generation	With Purchased Power	With New Nuclear Capacity	With Wind Energy	With Combined Wind Energy, PV Solar Energy, & Gas-Fired Generation
Approximately 910 full time employees		Approximately 94 employees (Section 7.2.2.1)	Approximately 326 employees (Section 7.2.2.2)		Approximately 750 employees (Section 7.2.2.4)	Approximately 390 employees (Section 7.2.2.5)	
			Land Use Impacts				
SMALL – Adopting by reference Category 1 issue findings ([Appendix A], Table A-1, Issues 1 and 2)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 78).	SMALL – 38 ha (94 ac) for facility at existing power plant location. Two new gas pipelines would be built within existing ROW to connect with existing gas pipeline corridor (Section 7.2.2.1)	SMALL to MODERATE – 154 ha (382 ac) on an existing site required for the power block and associated facilities; 7.7 ha (19 ac) for ash and scrubber sludge disposal (Section 7.2.2.2)	SMALL to MODERATE – Most transmission facilities could be constructed along existing transmission ROW (Section 7.2.2.3). Depending on the fuel used to generate the purchased power, impacts would be similar to those described for the energy alternatives (Section 7.2.2.3)	SMALL to MODERATE – 104 ha (258 ac) required for the power block and associated facilities at an existing power plant site (Section 7.2.2.4)	LARGE – Total direct impact area based on 2011 PJM capacity credit is 1,440 ha (3,560 ac) and based on 2025 PJM capacity credit is 433 ha (1,070 ac). Overall affected area based on 2011 PJM capacity credit is 172,400 ha (426,000 ac) and 51,720 ha (127,800 ac) based on 2025 PJM capacity credits. (Section 7.2.2.5)	LARGE – Large land areas required for wind and solar power generation

Table 8.0-2 Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decom-missioning)	With Gas-Fired Generation	With Coal-Fired Generation	With Purchased Power	With New Nuclear Capacity	With Wind Energy	With Combined Wind Energy, PV Solar Energy, & Gas-Fired Generation
Water Resources Impacts							
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 9, 10, 12-15, 18-21, and 24). One Category 2 surface water issue applies (Section 4.5.1, Issue 17) and three Category 2 groundwater issues apply (Section 4.5.2.2, Issue 23; Section 4.5.2.3, Issue 26; and Section 4.5.2.4, Issue 27).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 78).	SMALL – Construction impacts minimized by use of best management practices. Reduced cooling water demands, inherent in combined-cycle design (Section 7.2.2.1)	SMALL – Construction impacts minimized by use of best management practices. Operational impacts similar to LSCS by using closed –cycle cooling system with withdrawals from and discharges to a surface water source similar to those of LaSalle (Section 7.2.2.2)	SMALL to MODERATE– Depending on the fuel used to generate the purchased power, impacts would be similar to those described for the energy alternatives (Section 7.2.2.3)	SMALL – Construction impacts minimized by use of best management practices. Operational impacts similar to LSCS by using cooling towers with withdrawals from and discharges to a surface water source (Section 7.2.2.4)	SMALL – Construction impacts minimized by use of best management practices. No consumptive water use (Section 7.2.2.5)	SMALL – Construction impacts minimized by use of best management practices. wind, PV and combined cycle facilities use minimal water
Air Quality Impacts							
SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 5).	SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issue 78)	MODERATE – 36 tons SO_2/yr; 591 tons NO_x/yr; 123 tons CO/yr; 103 tons $PM_{2.5}$/yr; 5,963,000 tons CO_2 /yr (Section 7.2.2.1)	MODERATE – 5,750 tons SO_x/yr; 1,640 tons NO_x/yr; 2,280 tons CO/yr; 16 tons $PM_{2.5}$/yr; 61 tons PM_{10}/yr; 0.14 tons mercury/yr; 21,933,000 tons CO_2 /yr (Section 7.2.2.2)	SMALL to MODERATE – Depending on the fuel used to generate the purchased power, impacts would be similar to those described for the energy alternatives (Section 7.2.2.3)	SMALL – Air emissions are primarily from non-generation equipment and diesel generators and are comparable to those associated with the continued operation of LSCS (Section 7.2.2.4)	SMALL -Minimal air emissions during operation (Section 7.2.2.5)	SMALL to MODERATE – Gas-fired combustion turbine emits air pollutants similar to gas-fired alternative, but at approximately 19% of the amounts
Ecological Resource Impacts							
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 29, 30, 32,	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 78)	SMALL – Construction of pipeline could alter the terrestrial habitat, but	SMALL to MODERATE –154 ha (382 ac) would be required for the new power block	SMALL to MODERATE – Depending on the fuel used to generate the	SMALL to MODERATE– Construction could affect terrestrial habitats. Impacts of	SMALL to MODERATE – Potential for impact include loss of habitat, habitat	LARGE - Potential for impact include habitat avoidance, and bird and bat mortality; extensive

Table 8.0-2 Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decom-missioning)	With Gas-Fired Generation	With Coal-Fired Generation	With Purchased Power	With New Nuclear Capacity	With Wind Energy	With Combined Wind Energy, PV Solar Energy, & Gas-Fired Generation
34, 35, 38, 41-45, 47, and 49). Five Category 2 issues apply (Section 4.6.2.1, Issue 28; Section 4.6.2.2, Issue 33; Section 4.6.3.1, Issue 36; Section 4.6.3.2, Issue 3; and Section 4.6.3.3, Issue 46)		construction on an existing site would minimize habitat disturbances. Impacts to aquatic resources would be small. (Section 7.2.2.1)	and coal storage; 7.7 ha (19 ac) of the existing site could be required for ash/sludge disposal. Impacts to aquatic resources would be small. (Section 7.2.2.2)	purchased power, impacts would be similar to those described for the energy alternatives; the need for transmission lines could affect terrestrial and aquatic resources (Section 7.2.2.3)	operations would be comparable to those associated with continued operation of LSCS. Impacts to aquatic resources would be small. (Section 7.2.2.4)	avoidance, and bird and bat mortality (Section 7.2.2.5)	loss of habitat beneath solar collectors due to clearing, shading and loss of precipitation, and maintenance
Threatened or Endangered Species Impacts[1]							
NOT LIKELY TO ADVERSELY AFFECT – One Category 2 issue applies (Section 4.6.4.1, Issue 50)	Not an impact evaluated by Decommissioning GEIS (NRC 1996c)	NOT LIKELY TO ADVERSELY AFFECT – Federal and state laws prohibit Federal projects from destroying or adversely affecting protected species and their habitats	NOT LIKELY TO ADVERSELY AFFECT – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	NOT LIKELY TO ADVERSELY AFFECT – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats (Section 7.2.2.3)	NOT LIKELY TO ADVERSELY AFFECT – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	NOT LIKELY TO ADVERSELY AFFECT – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	NOT LIKELY TO ADVERSELY AFFECT – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats
Human Health Impacts							
SMALL – Adopting by reference Category 1 issues (Table A-1, Issues 57-59, 61, and 63). One Category 2 issue applies Microbiological hazards (Section 4.9.1, Issue 60)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 78)	SMALL TO MODERATE– Adopting by reference GEIS conclusion that some risk of cancer and emphysema exists from emissions (NRC 2013b)	MODERATE – Adopting by reference GEIS conclusion that risks such as cancer and emphysema from emissions are likely (NRC 2013b)	SMALL to MODERATE – Depending on the fuel used to generate the purchased power, impacts would be similar to those described for the energy alternatives (Section 7.2.2.3)	SMALL – Impacts would be comparable to continued operation of LSCS (Section 7.2.2.4)	SMALL -Adequate siting distances can minimize sound and vibration impacts (Section 7.2.2.5)	SMALL to MODERATE - Air emissions from combustion turbines

Table 8.0-2 Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decom-missioning)	With Gas-Fired Generation	With Coal-Fired Generation	With Purchased Power	With New Nuclear Capacity	With Wind Energy	With Combined Wind Energy, PV Solar Energy, & Gas-Fired Generation
Socioeconomic Impacts							
SMALL– Adopting by reference Category 1 issue findings (Table A-1, Issues 52-56). One Category 2 issue applies – Environmental Justice (Section 4.10.1, Issue 67)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 78)	SMALL to MODERATE – Small, temporary impacts due to construction and moderate impacts from loss of 910 jobs at the LSCS site (Section 7.2.2.1)	SMALL to MODERATE – Small, temporary impacts due to construction and moderate impacts from loss of 910 jobs at the LSCS site (Section 7.2.2.2)	MODERATE – Small impacts at the sites of the existing plants, and moderate impacts from loss of 910 jobs at the LaSalle site could adversely affect surrounding counties (Section 7.2.2.3)	Construction: SMALL to MODERATE – Peak construction workforce of 4,282 could temporarily affect housing and public services in surrounding counties – severity of impacts would depend on location of the plant site. Operation: SMALL to MODERATE – reduction in personnel at LSCS could adversely affect surrounding counties; new reactor(s) would require 750 personnel severity of impacts would depend on location of the plant site. (Section 7.2.2.4)	SMALL to MODERATE –Wind energy development might not be compatible with land uses such as housing developments, airport approaches, some radar installations, and low-level military flight training routes; could require worker relocation to remote areas; reduction in 910 personnel at LSCS could adversely affect surrounding counties (Section 7.2.2.5)	SMALL to MODERATE - Reduction in permanent work force at LSCS could adversely affect surrounding counties

Table 8.0-2 Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decom-missioning)	With Gas-Fired Generation	With Coal-Fired Generation	With Purchased Power	With New Nuclear Capacity	With Wind Energy	With Combined Wind Energy, PV Solar Energy, & Gas-Fired Generation
			Waste Management Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 68, 69, 71, and 72)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 78)	SMALL – The only noteworthy waste would be a small amount of spent catalyst from spent selective catalytic reduction (SCR) used for NO_x control. (Section 7.2.2.1)	SMALL – 42,700 tons of non-recycled coal ash and 19,500 tons of scrubber sludge annually would require 7.7 ha (19 ac) for disposal over a 20-year period. (Section 7.2.2.2)	SMALL to MODERATE – Depending on the fuel used to generate the purchased power, impacts would be similar to those described for the energy alternatives (Section 7.2.2.3)	SMALL – Non-radioactive and radioactive wastes would be similar to those associated with the continued operation of LSCS (Section 7.2.2.4)	SMALL -Waste generation in minor quantities during operation (Section 7.2.2.5)	SMALL- Waste generation in minor quantities during operation
			Visual/Aesthetic Impacts				
SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 4)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 78)	SMALL – Visual and noise impacts would be consistent with industrial nature of selected site (Section 7.2.2.1)	SMALL – Visual and noise impacts would be consistent with the industrial nature of the site (Section 7.2.2.2)	SMALL to MODERATE – Depending on the fuel used to generate the purchased power, impacts would be similar to those described for the energy alternatives (Section 7.2.2.3)	SMALL – Visual and noise impacts would be comparable to those from existing LSCS facilities (Section 7.2.2.4)	MODERATE to LARGE – Visual impacts would be considerable due to the number and size of wind turbines that would be required to provide between 4,270 MWe and 14,250 MWe of new wind capability, and because they would be prominent from afar in the open landscape and over a large area. Noise impacts would be consistent with or less than at other industrial sites (Section 7.2.2.5)	MODERATE to LARGE - Comparable to combined wind and solar visual impacts

Table 8.0-2 Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decom-missioning)	With Gas-Fired Generation	With Coal-Fired Generation	With Purchased Power	With New Nuclear Capacity	With Wind Energy	With Combined Wind Energy, PV Solar Energy, & Gas-Fired Generation
Cultural Resources[2]							
NO ADVERSE EFFECT – One Category 2 issue applies – SHPO consultation minimizes potential for impact (Section 4.6.4.1, Issue 51)	NO ADVERSE EFFECT – Adopting by reference Category 1 issue finding (Table A-1, Issue 78)	NO RESOURCE PRESENT to ADVERSE EFFECT – some states do not have cultural resource protection regulations (Section 7.2.2.1)	NO RESOURCE PRESENT to ADVERSE EFFECT – some states do not have cultural resource protection regulations (Section 7.2.2.2)	NO RESOURCE PRESENT to ADVERSE EFFECT – some states do not have cultural resource protection regulations (Section 7.2.2.3)	NO ADVERSE EFFECT – protection of archaeological and cultural resources would be implemented consistent with applicable state and federal requirements which must include SHPO consultation, if effects would be significant, due to NRC licensing involvement (Section 7.2.2.4)	NO RESOURCE PRESENT to ADVERSE EFFECT – some states do not have cultural resource protection regulations (Section 7.2.2.5)	NO RESOURCE PRESENT to ADVERSELY AFFECTED – some states do not have cultural resource protection regulations

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.
MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.
LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource.
(10 CFR 51, Subpart A, Appendix B, Table B 1, Footnote 3).
ROW = right of way
[1]Effects on threatened or endangered species may be characterized as follows: (1) no effect, (2) not likely to adversely affect, (3) likely to adversely affect, (4) likely to jeopardize continued existence
[2] Effects on historic properties may be characterized as follows: (1) no historic properties present, (2) historic properties are present, but not adversely affected, or (3) historic properties are adversely affected (from 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Footnote 3).

Chapter 9

Status of Compliance

9.1 Proposed Action

NRC

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

9.1.1 General

Table 9.1-1 lists environmental authorizations Exelon Generation has obtained for current LSCS operations. In this context, Exelon Generation uses "authorizations" to include any permits, licenses, approvals, or other entitlements. Exelon Generation expects to continue renewing these authorizations, as appropriate, during the current license period and throughout the period of extended operation associated with renewal of the LSCS operating licenses. Because the NRC regulatory focus is prospective, Table 9.1-1 does not include authorizations that Exelon Generation obtained for past activities that did not include continuing obligations.

Preparatory to applying for renewal of the LSCS licenses to operate, Exelon Generation conducted an assessment to identify new and significant environmental information (Chapter 5). The assessment included interviews with subject experts, review of LSCS environmental documentation, and communication with state and federal environmental protection agencies. Based on this assessment, Exelon Generation concludes that LSCS is in substantive compliance with applicable environmental standards and requirements. Minor deviations from applicable standards or requirements are corrected, and notification is provided to regulatory agencies, as required. Table 9.1-2 lists additional environmental authorizations and consultations related to NRC renewal of the LSCS license to operate. As indicated, Exelon Generation anticipates needing relatively few such additional authorizations and consultations. Sections 9.1.2 through 9.1.5 discuss some of these items in more detail.

9.1.2 Threatened or Endangered Species

Section 7 of the Endangered Species Act (16 USC 1531 et seq.) requires federal agencies to ensure that their actions are not likely to jeopardize the continued existence of species that are listed, or proposed for listing, as endangered or threatened. Depending on the action involved, the Act requires consultation with the U.S. Fish and Wildlife Service (USFWS), regarding effects on non-marine species, and with the National Marine Fisheries Service (NMFS), when marine species could be affected. USFWS and NMFS have issued joint procedural regulations at 50 CFR Part 402, Subpart B, that address consultation, and USFWS maintains the joint list of threatened or endangered species at 50 CFR Part 17. Because LSCS's continued operations would not affect any endangered or threatened marine species, consultation with NMFS is not required and was not done.

Although not required of an applicant by federal law or NRC regulation, Exelon Generation has chosen to invite comment from USFWS regarding potential effects that LSCS license renewal might have. Appendix D includes copies of Exelon Generation correspondence with USFWS.

9.1.3 Historic Preservation

Section 106 of the National Historic Preservation Act (16 USC 470 et seq.) requires federal agencies having the authority to license any undertaking to consider the effect of the undertaking on historic properties and to afford the Advisory Council on Historic Preservation an opportunity to comment on the undertaking, prior to the agency issuing the license. Advisory Council regulations provide for the State Historic Preservation Officer (SHPO) to have a consulting role (35 CFR 800.2). Although not required of an applicant by federal law or NRC regulation, Exelon Generation has chosen to invite comment on the proposed license renewal for LSCS from the Illinois SHPO. Appendix E includes copies of Exelon Generation correspondence with the SHPO regarding potential effects that LSCS license renewal might have on historic or cultural resources.

9.1.4 Water Quality (401) Certification

Federal Clean Water Act (CWA) Section 401 requires an applicant seeking a federal license for an activity that may result in a discharge to navigable waters to provide the federal licensing agency with a certification, or a waiver of certification, by the state where the discharge would originate. If no waiver is issued by the state, its certification must indicate that applicable state water quality standards will not be violated as a result of the discharge (33 USC 1341).

The NRC indicated in its GEIS that issuance of an NPDES permit by a state implies continued Section 401 certification by the state (NRC 2013b). Section 402(b) of the Clean Water Act provides that the Governor of any state can apply to the Administrator of the EPA to administer the NPDES Program in the State. On October 23, 1977, the Illinois State NPDES Permit Program was approved by the EPA, giving Illinois authorization to implement the NPDES permitting program. Accordingly, as evidence of Section 401 certification by Illinois for plant operations during the initial license term, Exelon Generation is providing the current LSCS NPDES permit (IL0048151) which was issued July 5, 2013 with an effective date of August 1, 2013, and an expiration date of July 31, 2018 (included in Appendix C).

In accordance with CWA Section 401 and Illinois EPA guidance, by letter dated February 4, 2014 (see Appendix B), Exelon Generation filed with Illinois EPA, Illinois DNR, and the U.S. Army Corps of Engineers, an application for certification that plant operation during the LSCS license renewal terms will comply with Illinois state water quality standards. Determination by Illinois EPA of the application's completeness and initiation of the agency's technical review are expected to occur upon Exelon Generation's filing with the NRC of the LaSalle County Station, Units 1 and 2 License Renewal Application. Responses from the Illinois DNR and U.S. Army Corps of Engineers (see Appendix B) indicate that permits from these agencies are not required to support renewal of the LSCS NRC operating licenses, and neither agency objects to issuance of the requested CWA Section 401 certification.

9.1.5 Coastal Zone Management Program

The Federal Coastal Zone Management Act (CZMA) (16 USC 1451 et seq.) imposes requirements on applicants for a federal license to conduct an activity that could affect a state's coastal zone (NRC 2009). The Act requires the applicant to certify to the licensing agency that the proposed activity would be consistent with the state's federally approved coastal zone management program [16 USC 1456(c)(3)(A)]. The National Oceanic and Atmospheric

Administration (NOAA) has promulgated implementing regulations that indicate that the requirement is applicable to renewal of federal licenses for activities not previously reviewed by the state [15 CFR 930.51(b)(1)]. The regulation requires that the license applicant provide its certification to the federal licensing agency and a copy to the applicable state agency [15 CFR 930.57(a)].

Participation in the NOAA Coastal Zone Management Program is voluntary; federal assistance is given to states willing to develop and implement a comprehensive coastal management program. Illinois DNR is the lead agency for implementing a comprehensive coastal management program for protection of the Great Lakes in Illinois. In January 2009, Illinois DNR submitted a draft program document to NOAA's Ocean and Coastal Resource Management's Coastal Programs Division. NOAA approved it on January 31, 2012 (NOAA 2012).

The inland boundary of the Illinois coastal zone includes parts of Cook and Lake Counties and parts of the Chicago and Calumet River watersheds (NOAA/IDNR 2011). LSCS is outside the boundaries of the Illinois coastal zone, and therefore, no certification of consistency with the Illinois coastal zone management program is required.

Table 9.1-1 Environmental Authorizations for Current LSCS Operations

Agency	Authority	Requirements	Number	Issue or Expiration Date	Activity Covered
			Federal and State Requirements		
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.), 10 CFR 50.10	License to operate	NPF-11	Issued: 04/17/1982 Expires: 04/17/2022	Operation of LSCS Unit 1
			NPF-18	Issued: 12/16/1983 Expires: 12/16/2023	Operation of LSCS Unit 2
U.S. Army Corps of Engineers	Rivers and Harbors Act of 1899 (33 USC 403 Section 10)	Department of Army Permit	CEMVR-OD-P-2006-185	Issued: 04/16/2006 Expires: 12/31/2015	Maintenance dredging at river screen house intake
Illinois Environmental Protection Agency, Division of Water Pollution Control	Clean Water Act (33 USC Section 1251 et seq.), Illinois Administrative Code Title 35, Part 309	NPDES Permit	IL0048151	Issued: 07/05/2013 Expires: 07/31/2018	Discharges to Illinois River or its tributaries of (1) cooling reservoir blowdown water mixed with other process water and (2) storm water runoff
Illinois Environmental Protection Agency, Division of Air Pollution Control	Federal Clean Air Act (42 USC 7401), 40 CFR 70, and Illinois Administrative Code 35 IAC 201	FESOP	Application #75040086 ID# 099802AAA	Issued: 12/11/2000 Expires: 12/11/2005 Renewal application submitted 07/15/2005[1]	Air emissions from emergency generators, storage tanks and dispensing facilities
Illinois Environmental Protection Agency, Bureau of Land	35 IAC 722	Notification of Hazardous Waste Activity	ILD000803643	Not Applicable	Small quantity generator of hazardous waste
Illinois Department of Natural Resources, Office of Water Resources	Rivers, Lakes and Streams Act (615 ILCS 5) Illinois Administrative Code 17 IAC 3702	Dam Safety	DS2000237	Issued: 12/20/2000 Expires: Not applicable	Operation and maintenance of cooling reservoir dam

Table 9.1-1 Environmental Authorizations for Current LSCS Operations (Continued)

Agency	Authority	Requirements	Number	Issue or Expiration Date	Activity Covered
Federal and State Requirements					
Illinois Emergency Management Agency, Division of Nuclear Safety	32 IAC 609	Waste tracking permit	IL-0104	Not Applicable	Shipments of low- level radioactive waste
Tennessee Department of Environment and Conservation	Tennessee Code Annotated 68-202-206	License to deliver radioactive material	T-IL009-L14	Renewed annually	License to deliver radioactive material to processing facility in Tennessee
Utah Department of Environmental Quality	Utah Rule 313-26	Permit to deliver radioactive material	010000028	Renewed annually	Permit to deliver radioactive material to disposal facility in Utah

NPDES – National Pollutant Discharge Elimination System

FESOP – Federally Enforceable State Operating Permit

[1] 415 Illinois Complied Statutes 5/-, Title II, Air Pollution, Sec. 9.1(f) extends the effective term of the FESOP if the permit holder submits a completed application for renewal to the IEPA at least 90 days prior to the permit expiration. Because Exelon Generation met this requirement, the permit is administratively extended (415 ILCS 5/9.1)

Table 9.1-2 Environmental Authorizations for LSCS License Renewal[a]

Agency	Authority	Requirement	Remarks
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.)	License renewal	Applicant for federal license must submit an Environmental Report in support of license renewal application
U.S. Fish and Wildlife Service	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Federal agency issuing a license must consult with the USFWS, and NMFS, if applicable, regarding federally-protected species
Illinois Environmental Protection Agency	Clean Water Act Section 401 (33 USC 1341)	Certification	Applicant seeking federal license for a project with discharge to state waters must obtain either State certification that proposed action would comply with applicable State water quality standards, or a waiver
Illinois Historic Preservation Agency	National Historic Preservation Act Section 106 (16 USC 470f)	Consultation	Federal agency issuing a license must consider cultural impacts and consult with State Historic Preservation Officer

[a] No requirements related to NRC license renewal were identified for local or other agencies

9.2 Alternatives

NRC

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

The coal, gas, purchased power, new nuclear, renewables and combination alternatives discussed in Chapter 7 could be constructed and operated to comply with applicable environmental quality standards and requirements. Exelon Generation notes that increasingly stringent air quality protection requirements could make the construction of a large fossil-fueled power plant infeasible in many locations. Exelon Generation also notes that the EPA has revised its requirements for design and operation of cooling water intake structures at new and existing facilities (40 CFR Part 125, Subparts I and J). These requirements could necessitate construction of cooling towers and other technologies for the coal- and gas-fired and new nuclear alternatives.

Chapter 10

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10.0 References

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Appendix A

NRC NEPA Issues for License Renewal of Nuclear Power Plants

Exelon Generation has prepared this environmental report in accordance with the requirements of NRC regulation 10 CFR 51.53. NRC included in the regulation the list of 78 National Environmental Policy Act (NEPA) issues for license renewal of nuclear power plants that were identified in the 2013 GEIS (Appendix B to Subpart A of 10 CFR Part 51, Table B-1).

Table A-1, below, lists the 78 issues from 10 CFR Part 51, Appendix B, Table B-1 and identifies the section in this environmental report in which Exelon Generation addresses each applicable issue. For organization and clarity, Exelon Generation has assigned a number to each issue and uses the issue numbers throughout the environmental report.

Table A-1. LaSalle Units 1 and 2 Environmental Report Cross-Reference of License Renewal NEPA Issues.

No.	Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
	Land Use			
1	Onsite land use	1	4.1	4.2.1.1/4-6
2	Offsite land use	1	4.1	4.2.1.1/4-7
3	Offsite land use in transmission line rights-of-way	1	2.2.6	Issue applies to a feature (in-scope offsite transmission lines) that LaSalle does not have
	Visual Resources			
4	Aesthetic impacts	1	4.1	4.2.1.2/4-9
	Air Quality			
5	Air quality (all plants)	1	4.2	4.3.1.1/4-14
6	Air quality effects of transmission lines	1	2.2.6	Issue applies to a feature (in-scope offsite transmission lines) that LaSalle does not have
	Noise			
7	Noise impacts	1	4.3	4.3.1.2/4-19
	Geologic Environment			
8	Geology and soils	1	4.4	4.4/4-29
	Surface Water Resources			
9	Surface water use and quality (non-cooling system impacts)	1	4.0.1	4.5.1.1/4-30
10	Altered current patterns at intake and discharge structures	1	4.0.1	4.5.1.1/4-36
11	Altered salinity gradients	1	NA	Issue applies to coastal plants located on estuaries.
12	Altered thermal stratification of lakes	1	4.0.1	4.5.1.1/4-37
13	Scouring caused by discharged cooling water	1	4.0.1	4.5.1.1/4-38
14	Discharge of metals in cooling system effluent	1	4.0.1	4.5.1.1/4-38

Table A-1. LaSalle Units 1 and 2 Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

No.	Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
15	Discharge of biocides, sanitary wastes, and minor chemical spills	1	4.0.1	4.5.1.1/4-39
16	Surface water use conflicts (plants with once-through cooling systems)	1	NA	Issue applies to a feature (once-through cooling system) that LaSalle does not have.
17	Surface water use conflicts (plants with cooling ponds, or cooling towers using makeup water from a river)	2	4.5.1	4.5.1.1/4-41
18	Effects of dredging on surface water quality	1	4.0.1	4.5.1.1/4-42
19	Temperature effects on sediment transport capacity	1	4.0.1	4.5.1.1/4-43
	Groundwater Resources			
20	Groundwater contamination and use (non-cooling system impacts)	1	4.0.1	4.5.1.2/4-45
21	Groundwater use conflicts (plants that withdraw <100 gpm)	1	4.0.1	4.5.1.2/4-47
22	Groundwater use conflicts (plants that withdraw >100 gpm)	2	4.5.2.1	Issue applies to a feature (groundwater use > 100 gpm) that LaSalle does not have.
23	Groundwater use conflicts (plants with closed-cycle cooling systems that withdraw makeup water from a river)	2	4.5.2.2	4.5.1.2/4-48
24	Groundwater quality degradation resulting from water withdrawals	1	4.0.1	4.5.1.2/4-49
25	Groundwater quality degradation (plants with cooling ponds in salt marshes)	1	NA	Issue applies to a feature (cooling ponds in salt marshes) that LaSalle does not have.
26	Groundwater quality degradation (plants with cooling ponds at inland sites)	2	4.5.2.3	4.5.1.2/4-51
27	Radionuclides released to groundwater	2	4.5.2.4	4.5.1.2/4-51
	Terrestrial Resources			
28	Effects on terrestrial resources (non-cooling system impacts)	2	4.6.2.1	4.6.1.1/4-59
29	Exposure of terrestrial organism to radionuclides	1	4.0.1	4.6.1.1/4-61

Table A-1. LaSalle Units 1 and 2 Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

No.	Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
30	Cooling system impacts on terrestrial resources (plants with once-through cooling systems or cooling ponds)	1	4.0.1	4.6.1.1/4-64
31	Cooling tower impacts on vegetation (plants with cooling towers)	1	NA	Issue applies to a feature (cooling towers) that LaSalle does not have.
32	Bird collisions with plant structures and transmission lines	1	4.0.1	4.6.1.1/4-70
33	Water use conflicts with terrestrial resources (plants with cooling ponds or cooling towers using makeup water from a river)	2	4.6.2.2	4.6.1.1/4-75
34	Transmission line ROW management impacts on terrestrial resources	1	2.2.6	4.6.1.1/4-75
35	Electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	2.2.6	Issue applies to a feature (offsite transmission lines) that LaSalle does not have.
	Aquatic Resources			
36	Impingement and entrainment of aquatic organisms (plants with once-through cooling systems or cooling ponds)	2	4.6.3.1	4.6.1.2/4-87
37	Impingement and entrainment of aquatic organisms (plants with cooling towers)	1	NA	Issue applies to a feature (cooling towers) that LaSalle does not have.
38	Entrainment of phytoplankton and zooplankton (all plants)	1	4.0.1	4.6.1.2/4-93
39	Thermal impacts on aquatic organisms (plants with once-through cooling systems or cooling ponds)	2	4.6.3.2	4.6.1.2/4-94
40	Thermal impacts on aquatic organisms (plants with cooling towers)	1	NA	Issue applies to a feature (cooling towers) that LaSalle does not have.
41	Infrequently reported thermal impacts (all plants)	1	4.0.1	4.6.1.2/4-97
42	Effects of cooling water discharge on dissolved oxygen, gas supersaturation, and eutrophication	1	4.0.1	4.6.1.2/4-100
43	Effects of non-radiological contaminants on aquatic organisms	1	4.0.1	4.6.1.2/4-103
44	Exposure of aquatic organisms to radionuclides	1	4.0.1	4.6.1.2/4-105

Table A-1. LaSalle Units 1 and 2 Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

No.	Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
45	Effect of dredging on aquatic organisms	1	4.0.1	4.6.1.2/4-107
46	Water use conflicts with aquatic resources (plants with cooling ponds or cooling towers using makeup water from a river)	2	4.6.3.3	4.6.1.2/4-109
47	Effects on aquatic resources (non-cooling system impacts)	1	4.0.1	4.6.1.2/4-110
48	Impacts of transmission line ROW management on aquatic resources	1	2.2.6	Issue applies to a feature (in-scope offsite transmission lines) that LaSalle does not have
49	Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4.0.1	4.6.1.2/4-113
	Special Status Species and Habitats			
50	Threatened, endangered, and protected species and essential fish habitat	2	4.6.4.1	4.6.1.3/4-115
	Historic and Cultural Resources			
51	Historic and cultural resources	2	4.7	4.7.1/4-122
	Socioeconomics			
52	Employment and income, recreation and tourism	1	4.8	4.8.1.1/4-127
53	Tax revenues	1	4.8	4.8.1.1/4-128
54	Community services and education	1	4.8	4.8.1.1/4-129
55	Population and housing	1	4.8	4.8.1.1/4-130
56	Transportation	1	4.8	4.8.1.1/4-131
	Human Health			
57	Radiation exposures to the public	1	4.0.1	4.9.1.1.1/4-140
58	Radiation exposures to plant workers	1	4.0.1	4.9.1.1.1/4-136
59	Human health impacts from chemicals	1	4.0.1	4.9.1.1.2/4-147

Table A-1. LaSalle Units 1 and 2 Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

No.	Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
60	Microbiological hazards to the public (plants with cooling ponds or canals or cooling towers that discharge to a river)	2	4.9.1	4.9.1.1.3/4-149
61	Microbiological hazards to plant workers	1	4.0.1	4.9.1.1.3/4-149
62	Chronic effects of electromagnetic fields	NA	-	4.9.1.1.4/4-150
63	Physical occupational hazards	1	4.0.1	4.9.1.1.5/4-156
64	Electric shock hazards	2	4.9.2	Issue applies to a feature (in-scope offsite transmission lines) that LaSalle does not have
	Postulated Accidents			
65	Design-basis accidents	1	4.0.1	4.9.1.2/4-158
66	Severe accidents	2	4.15	4.9.1.2/4-158
	Environmental Justice			
67	Minority and low-income populations	2	4.10.1	4.10.1/4-167
	Waste Management			
68	Low-level waste storage and disposal	1	4.11	4.11.1.1/4-171
69	On-site storage of spent nuclear fuel	1	4.11	4.11.1.2/4-172
70	Off-site radiological impacts of spent nuclear fuel and high-level waste disposal	1	4.13	4.11.1.3/4-175
71	Mixed waste storage and disposal	1	4.11	4.11.1.4/4-178
72	Non-radioactive waste storage and disposal	1	4.11	4.11.1.5/4-179
	Cumulative Impacts			
73	Cumulative Impacts	2	4.12	4.13/4-243
	Uranium Fuel Cycle			
74	Off-site radiological impacts – individual impacts from other than the disposal of spent fuel and high-level waste	1[c]	NA	4.12.1.1/4-193

Table A-1. LaSalle Units 1 and 2 Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

No.	Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
75	Off-site radiological impacts – collective impacts from other than the disposal of spent fuel and high- level waste	1	NA	4.12.1.1/4-194
76	Non-radiological impacts of the uranium fuel cycle	1	4.13	4.12.1.1/4-196
77	Transportation	1	4.13	4.12.1.1/4-196
Termination of Nuclear Power Plant Operations and Decommissioning				
78	Termination of plant operations and decommissioning	1	4.14	4.12.2.1/4-201

a. 10 CFR 51, Subpart A, Appendix A, Table B-1. (Issue numbers added to facilitate discussion.)
b. Generic Environmental Impact Statement for License Renewal of Nuclear Plants (NUREG-1437, Rev 1).
c. SECY-14-0072 (July 21, 2014)
NA = not applicable (Either the categorization and impact finding definitions do not apply to the issue, or the issue is not discussed in the ER because the issue applies to a plant feature that LaSalle does not have.)
– = The issue is not discussed in the ER because the NRC has determined that the categorization and impact finding definitions do not apply to the issue.
NEPA = National Environmental Policy Act

Appendix B

Clean Water Act Section 401 Certification

Table of Contents

Exelon Generation

February 4, 2014
RS-14-048

Mr. Dan Heacock, Facility Evaluation Unit Manager
Illinois Environmental Protection Agency, Bureau of Water
Post Office Box 19276
Springfield, IL 62794-9276

Subject: Application for Clean Water Act Section 401 Certification associated with Renewal of LaSalle County Station Units 1 and 2 Operating Licenses

Dear Mr. Heacock:

Not later than January 2015, Exelon Generation Company (Exelon) plans to file an application with the U.S. Nuclear Regulatory Commission (NRC) for renewal of the LaSalle County Station, Units 1 and 2 (LaSalle) operating licenses for 20 additional years beyond the currently licensed terms. No operational changes that would alter discharges or discharge pollutant loads from the LaSalle units during the extended operating terms would result from license renewal. Also, no construction is being proposed in connection with the license renewals.

In accordance with Section 401 of the federal Clean Water Act, the applicant for a federal license, such as renewed licenses for the LaSalle units, must provide the licensing agency with a certification by the state where the discharge would originate, indicating that applicable state water quality standards would not be violated as a result of discharges from the licensed facility. Thus, Exelon is filing the enclosed application requesting certification from the Illinois Environmental Protection Agency that renewal of the LaSalle operating licenses would not violate state water quality standards.

Consistent with the IEPA's established protocol for processing of Section 401 applications, copies of the application are being submitted in parallel to the Illinois Department of Natural Resources (IDNR) and the U.S. Army Corps of Engineers.

If there are questions, please feel free to contact either Roland Beem at (630) 657-3208 or Nancy Ranek at (610) 765-5369.

Respectfully,

Michael P. Gallagher

Michael P. Gallagher
Vice President, License Renewal Projects
Exelon Generation Company, LLC

Enclosure

cc: Illinois Department of Natural Resources (IDNR) (enclosure w/ attachments)
U.S. Army Corps of Engineers (enclosure w/ attachments)
Illinois Emergency Management Agency - Division of Nuclear Safety (enclosure *wo/* attachments)
Illinois Emergency Management Agency (Braidwood Representative) (enclosure *wo/* attachments)

JOINT APPLICATION FORM

1. Application Number (to be assigned by Agency)	2. Date 04 (Day) February (Month) 2014 (Year)	3. For agency use only (Date Received)

4. Name and address of applicant	5. Name, address, and title of authorized agent
Exelon Corporation Plant Manager, LaSalle County Station 2601 North 21st Road Marseilles, IL 61341 (815) 415-3700 ( )	Roland Beem Manager Environmental Programs Exelon Generation Co., LLC 4300 Winfield Rd Warrenville, IL 60555 Telephone no. during business hours include area code (630) 657-3208 ( )

6. Project Description and Remarks: Describe in detail the proposed activity, its purpose, and intended use. Also indicate the drainage area at the watershed to the downstream limit. Use attachments if needed.

See attached "6.0 LaSalle Project Description" (pages 5-19)

7. Names, addresses, and telephone numbers of all adjoining and potentially affected property owners, including the owner of the subject property if different from applicant.

See attached "7.0 Exelon LaSalle County Station License Renewal Adjacent Property Owners" (pages 20-30)

8. Location of activity

Illinois River
Name of waterway at location of the activity

Legal Description: See attached "8.0 Legal Description" (page 31)

1/4 Sec Twp Rge P.M.

UTM (Universal Transverse Mercator) If available
Zone North East

Address: 2601 North 21st Road
Street, road, or other descriptive location

Marseilles
In or near city or town

Brookfield Township
Name of Local Governing Community

LaSalle
County

IL
State

61341
Zip Code

9. Date activity is proposed to commence Ongoing Estimated Time of Construction Not applicable

10. Is any portion of the activity for which authorization is sought now complete? Yes No x If answer is "Yes" give reasons in item 6.

Month and Year the activity was completed Not applicable Indicate the existing work on drawings.

11. List all approvals or certifications required by other federal, interstate, state, or local agencies for any structures, construction, discharges, deposits, or other activities described in this application. If this form is being used for concurrent application to the Corps of Engineers, Illinois Department of Natural Resources, and Illinois Environmental Protection Agency, these agencies need not be listed.

Issuing Agency	Type of Approval	Identification No.	Date of Application	Date of Approval
U. S. Nuclear Regulatory Commission	Operating License Renewal	NPF-11 and NPF-18	Not later than January 2015	October 2016

12. Has any agency denied approval for the activity described herein or for any activity directly related to the activity described herein? Yes No x (If "Yes", explain in item 6.)

13. Application is hereby made for authorizations of the activities described herein. I certify that I am familiar with information contained in the application, and that to the best of my knowledge and belief, such information is true, complete, and accurate. I further certify that I possess the authority to undertake the proposed activities.

Michael P. Gallagher 2-4-2014
Signature of Applicant or Authorized Agent

Michael P. Gallagher – Vice President, License Renewal
Typed or Printed Name of Applicant or Authorized Agent

NCR FORM 426
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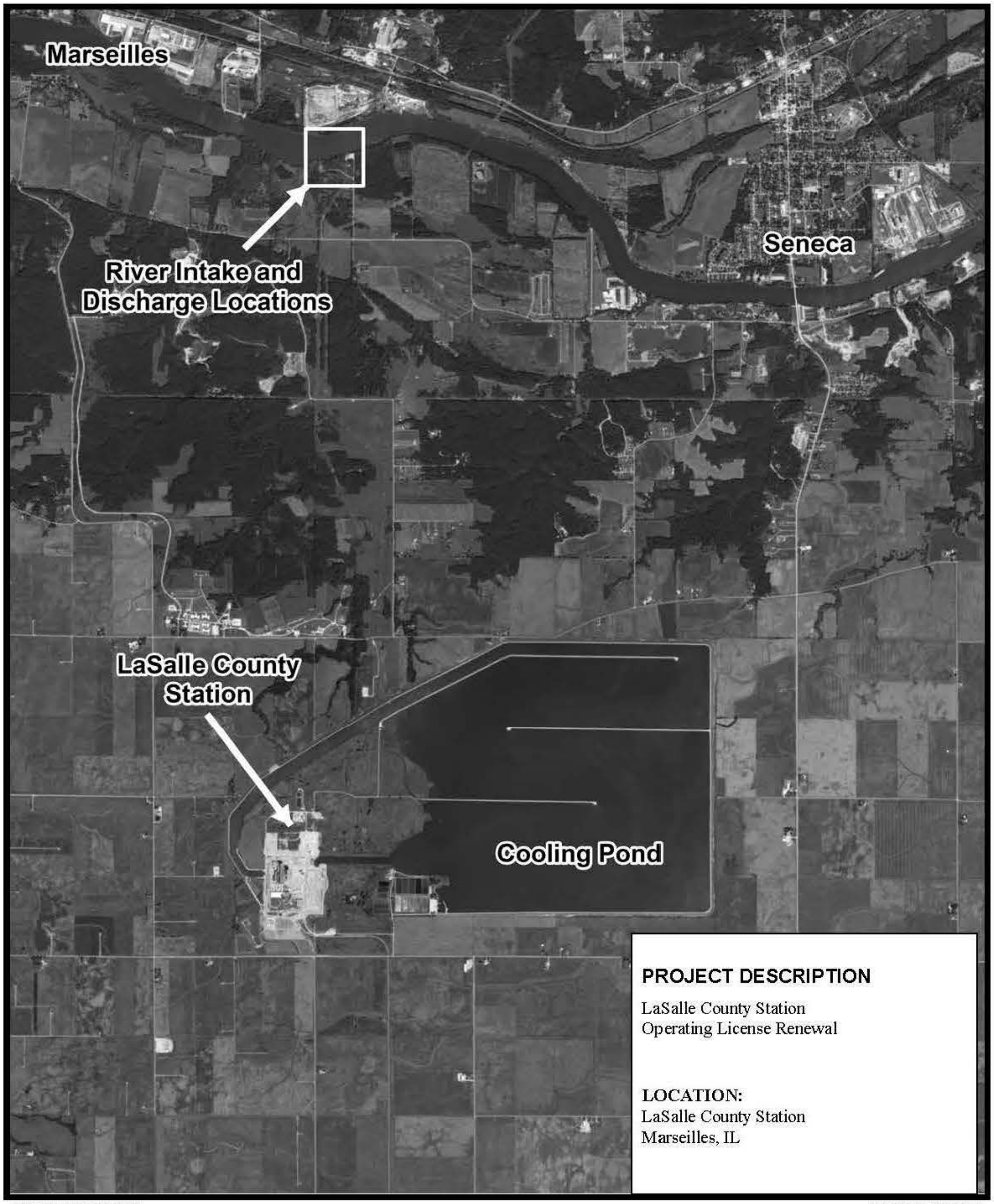

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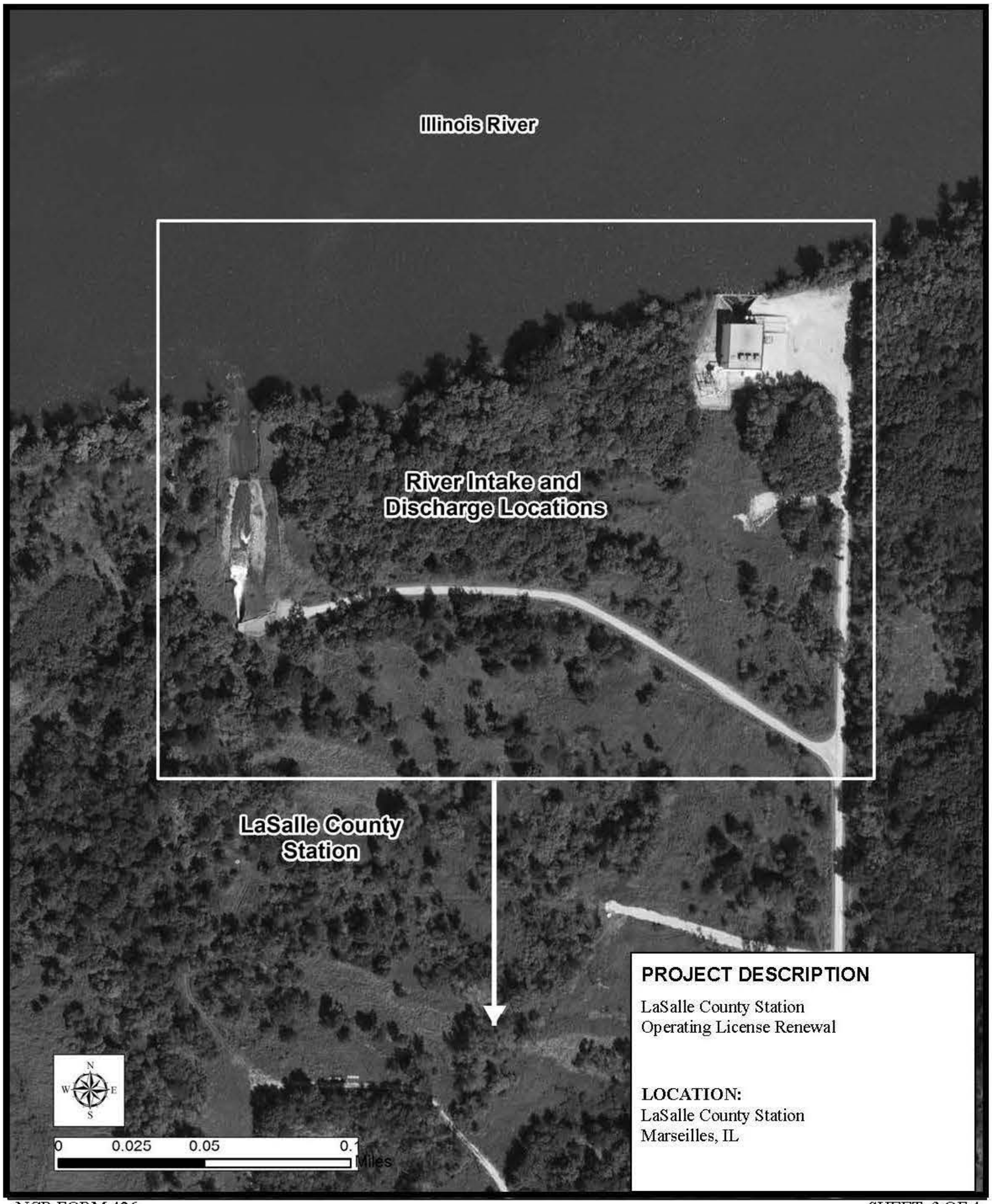

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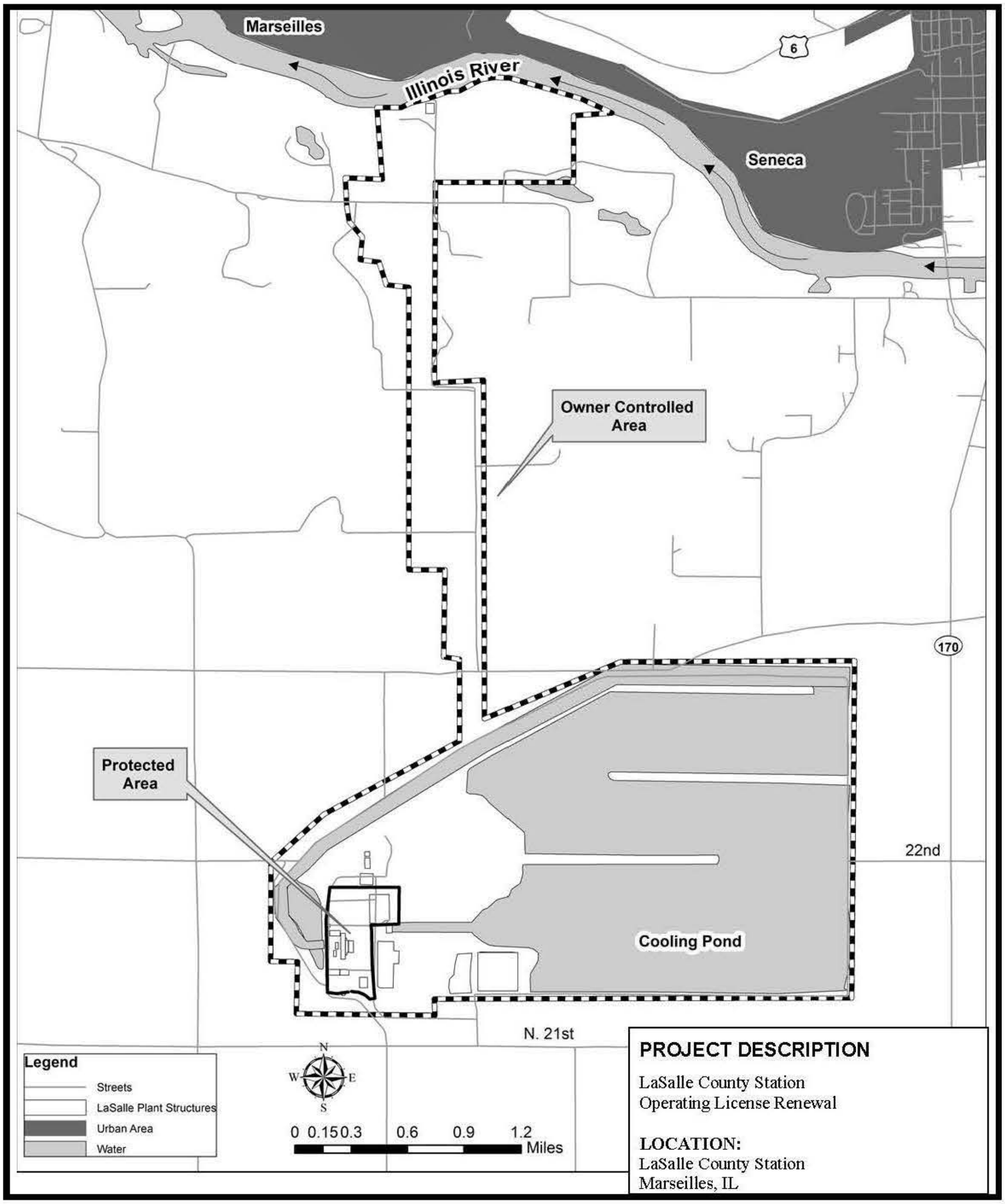

NCR FORM 426 SHEET 4 OF 4
08 AUG 02 ☐ CORPS OF ENGINEERS COPY ☐ IDNR/OWR COPY ☐ IEPA COPY ☐ APPLICANT'S COPY

6.0 LaSalle Project Description

6.1 Proposed Project

The project is the proposed renewal by the U.S. Nuclear Regulatory Commission (NRC) of the LaSalle County Station (LaSalle) Units 1 and 2 operating licenses for 20 additional years beyond the currently licensed terms. No operational changes would result from license renewal that would alter discharges or discharge pollutant loads from the LaSalle units during the extended operating terms. Also, no construction is being proposed in connection with the license renewals.

The NRC authorizes operation of domestic nuclear power plants in accordance with the Atomic Energy Act of 1954, as amended, and NRC implementing regulations. Nuclear power plants are initially licensed by the NRC to operate for 40 years, but these licenses may be renewed in accordance with NRC's regulation 10 CFR 50.51 for periods of up to 20 additional years, as indicated in 10 CFR 54.31. Exelon Generation, LLC (Exelon) operates LaSalle pursuant to NRC Operating Licenses NPF-11 (Unit 1) and NPF-18 (Unit 2). The existing license for LaSalle Unit 1 will expire on April 17, 2022, and the existing license for Unit 2 will expire on December 16, 2023. Exelon is seeking to renew the LaSalle operating licenses until 2042 and 2043, respectively.

LaSalle's discharges to the Illinois River are currently regulated by National Pollutant Discharge Elimination System (NPDES) permit IL0048151, issued by the Illinois Environmental Protection Agency (IEPA) on July 5, 2013, with an expiration date of July 31, 2018. The permit is provided in Attachment 1 to this application. Discharges from LaSalle Units 1 and 2 are subject to the effluent limits and conditions specified in this permit, which may be renewed or modified from time to time.

6.2 Plant Description

Figure 6-1 shows the LaSalle site. Major structures and facilities located on the LaSalle site and at the Illinois River are identified in Figures 6-2 and 6-3, respectively. Major features include:

- Unit 1 and Unit 2 reactor building, which houses the nuclear steam supply system, drywell, suppression pool, and primary containment for each unit as well as the new and spent fuel pools, refueling equipment, and emergency core cooling equipment;
- turbine building, where the power conversion equipment and feedwater cleanup equipment for both units are located;
- auxiliary building, which houses the control room, heating ventilation and air conditioning equipment, the station vent stack, and much of the station electrical switchgear;
- solid radioactive waste building;
- service building; and
- other structures and facilities of interest such as switchyard, intake and discharge structures on the Illinois River and at the cooling pond, Interim Radwaste Storage Facility, sewage treatment facility, and various additional support facilities.

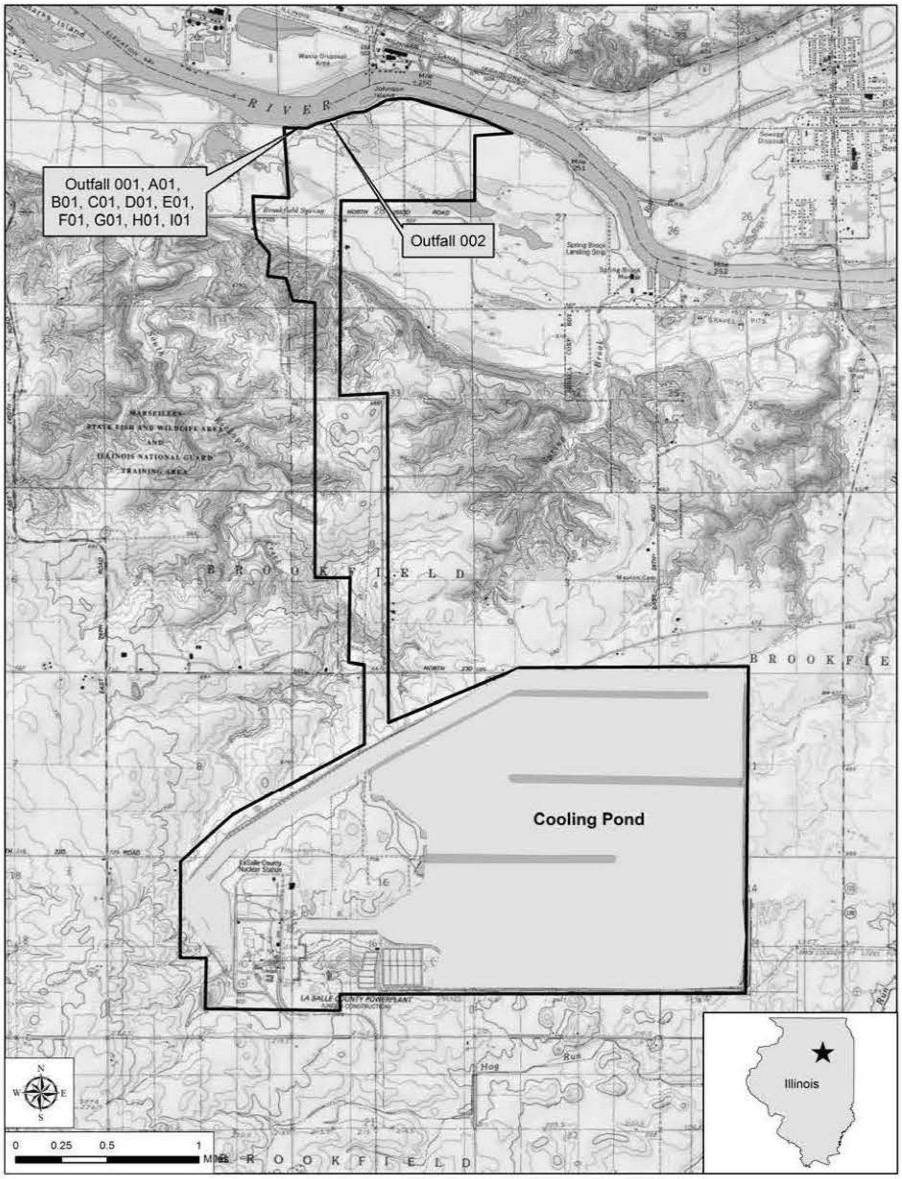

Figure 6-1. LaSalle Site Layout

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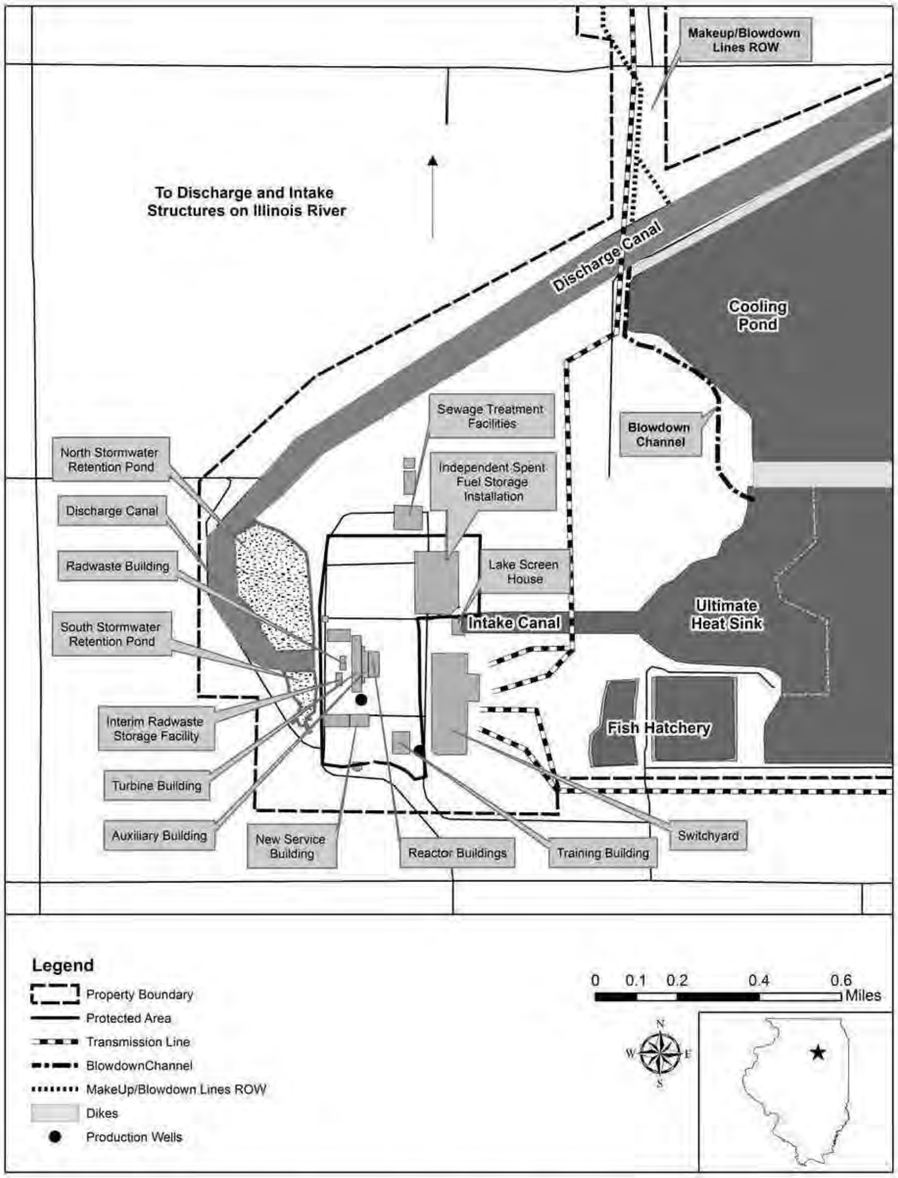

Figure 6-2. LaSalle Plant Layout

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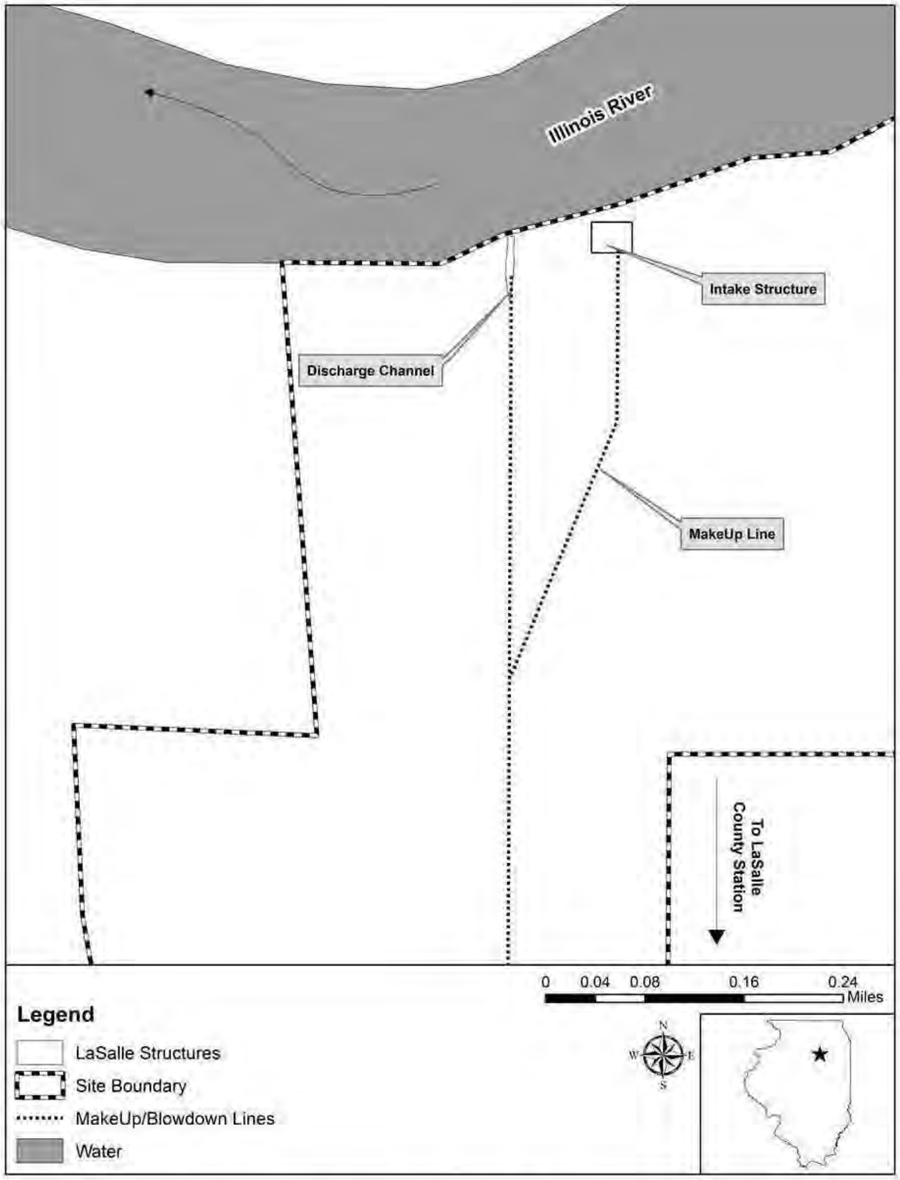

Figure 6-3. LaSalle Illinois River Structures Layout

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6.2.1 Water Systems

The power conversion system at LaSalle uses a 2,058-acre, perched, manmade pond for condenser cooling. The LaSalle circulating water system withdraws water from the cooling pond, through an intake structure ("lake screen house") on the west side of the pond (see Figure 6-1). Heated cooling water returns to the pond via a discharge canal along the north side of the cooling pond, and separated from the pond by a dike (see Figure 6-2). Two baffle berms within the cooling pond slow circulation and increase residence time of cooling water between discharge and intake. The cooling pond has a normal pond elevation of 700 feet mean sea level (MSL) and the normal volume is about 31,706 acre-feet.

Makeup water to replace water lost from the cooling pond to evaporation, seepage, or blowdown comes from the Illinois River. The blowdown line returns water from the cooling pond to the Illinois River (via Outfall 001) for the purpose of reducing the dissolved solids content in the recirculated cooling water. Figure 6-3 shows the intake and outfall locations.

Auxiliary water systems that support operation of the LaSalle reactors and use water from the cooling pond include the core standby cooling system (CSCS) equipment cooling water system and the service water system. The CSCS equipment cooling water system is equivalent in purpose to the essential service water systems at other nuclear stations. It withdraws cooling pond water from the LaSalle ultimate heat sink (UHS) for the purpose of cooling safety-related equipment necessary for safe shutdown of the reactors. The LaSalle UHS, also known as the core standby cooling system pond, is an 83-acre submerged area located directly in front of the lake screen house that has been excavated to a depth designed to hold enough water to support safe station shutdown from normal operating or accident conditions and subsequent cool down without makeup for 30 days. The service water system provides cooling water for various non-safety-related station auxiliary systems and components. The service water system also provides water for filling the fire protection system and to serve as a backup supply, water for the traveling screen wash, and water for the radwaste system.

Groundwater is used at LaSalle by the potable and sanitary water system as well as the demineralized water makeup system, which consists of demineralizers and filters located in a vendor trailer,

Figure 6-4 depicts water use within the plant and identifies permitted outfalls named in NPDES permit IL0048151. The following sections describe the water systems that contribute to these outfalls at LaSalle.

<u>6.2.1.1 Circulating Water System (CWS)</u>

The makeup water supplied to the LaSalle cooling pond is withdrawn from the Illinois River at the river screen house by three makeup pumps. Makeup water requirements can be met by operating one or two pumps for normal operations with one pump for backup. Each pump's rated capacity is 30,000 gallons per minute (gpm). Maximum water withdrawal from the Illinois River is, therefore, approximately 90,000 gpm. Normal water withdrawal with two pumps operating is up to 60,000 gpm. The intake system consists of an intake flume channeled into the bottom of the Illinois River and extending approximately 50 feet out from the shoreline. Recessed 24 feet from the shoreline is a 72 foot wide funnel inlet. At the mouth of the inlet, a floating boom has been installed to divert floating debris. The inlet leads to two adjacent bar racks and traveling screens, with 3/8 inch screen openings, in the river screenhouse. Debris removed from the traveling screens by a screen backwash system is collected in a trash basket and disposed in an offsite permitted landfill.

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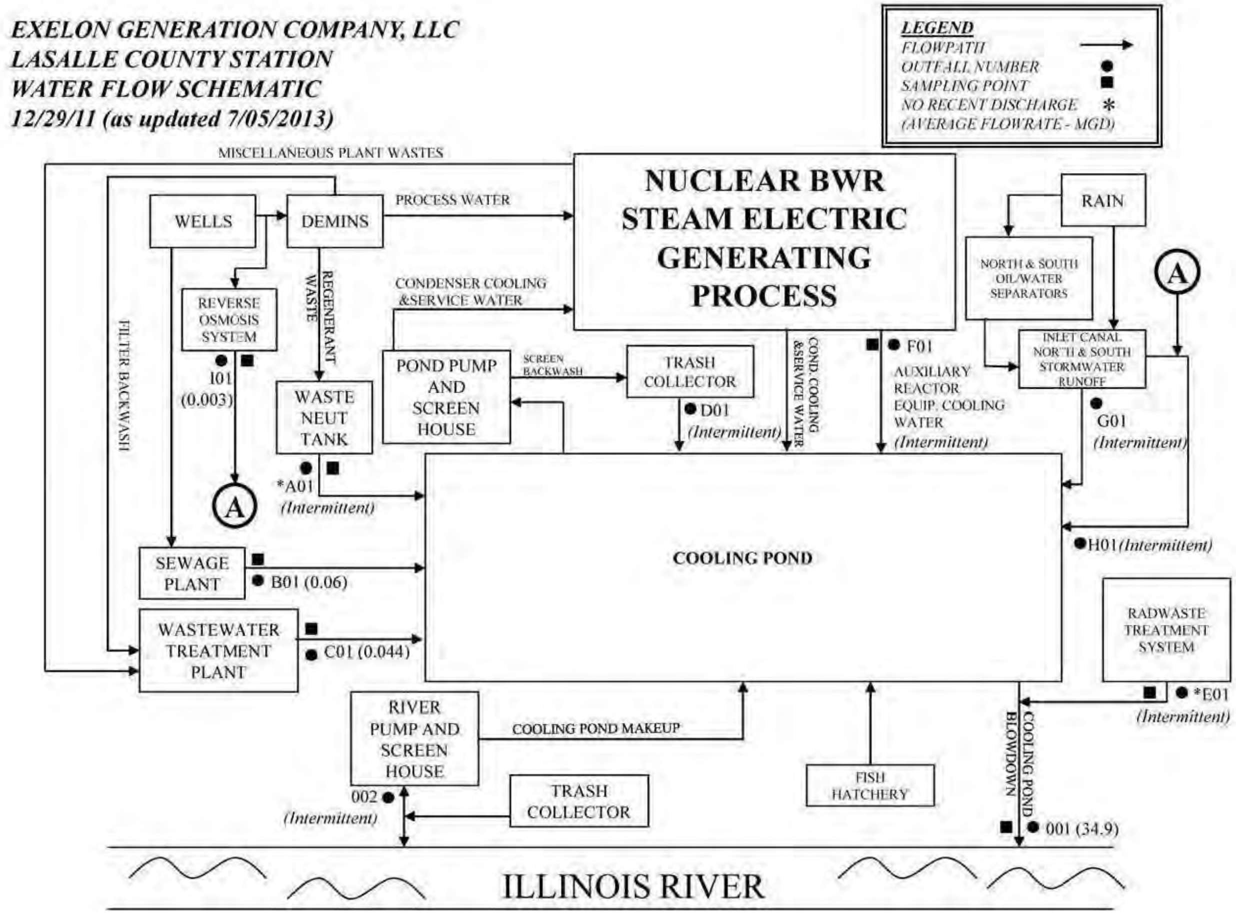

Figure 6-4. Flow Diagram for LaSalle Station

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The CWS intake on the cooling pond uses six circulating water pumps (three for each unit) in two separate bays of the lake screen house. For each unit, two circulating water pumps are normally in service and supply flow to the unit's condenser at an estimated 616,500 gpm. To protect the pumps from debris, each bay is fronted by bar grills, trash rakes, and traveling screens. Debris from the traveling screens and trash rakes is collected in a trash basket and disposed in an offsite permitted landfill. The CWS circulates water from the cooling pond, through the main condenser, and back to the pond. Pumps for fire water and non-essential service water also are located in the lake screen house. Administrative controls are in place to shut off the circulating water pumps and non-safety related service water pumps when the cooling pond level drops to an elevation of 690 feet to preserve the UHS pond.

The blowdown line originates in the cooler portion of the cooling pond. The line is designed for gravity flow and has a maximum discharge capacity of 90,000 gpm, but valve settings limit normal blowdown flow to 58,000 gpm or less with a target annual average of 30,000 gpm. Blowdown is discharged to the Illinois River through an outfall structure and rip rapped open channel (Outfall 001). The discharge is oriented perpendicular to the river bank approximately 1000 feet downstream of the LaSalle river screen house intake.

The CWS as well as the service water systems (described in Section 6.2.1.2) are treated for silt dispersion, scale and corrosion inhibition, and microbiological control. Sodium hypochlorite is added for biofouling control; carbon dioxide, zinc phosphate, polymer, azole, and hydroxyethylidenediphosphonic acid (HEDP) compounds are added for silt, scale and corrosion control.

6.2.1.2 Service Water System and CSCS Equipment Cooling Water System

As previously indicated, two auxiliary water systems at LaSalle use water from the cooling pond: the service water system supplies non-safety related systems and the CSCS equipment cooling water system supplies safety-related equipment necessary for safe shutdown of the reactors.

The service water system has five main pumps (16,000 gpm each) and two jockey pumps (5,000 gpm each) in the lake screen house. Normally, four main service water pumps are operated, two for each unit, with the fifth pump available as a backup for either unit. The service water jockey pumps would provide minimum flow requirements during a loss of offsite power. These jockey pumps can be connected to the emergency diesel generator. During shutdown and startup of either unit, the combination of main and jockey pumps can be adjusted to meet service water system cooling requirements.

The CSCS equipment cooling water system circulates cooling water from the UHS to safety related equipment. This system draws water from the service water tunnel in the basement of the lake screen house and discharges water back to the UHS portion of the cooling pond. Biocide, scale inhibitor/silt dispersant and corrosion inhibitor that are injected into the service water tunnel also serve to minimize biological fouling, microbiologically influenced corrosion, scaling, and silting of the CSCS equipment cooling water system.

6.2.1.3 Groundwater-Supplied Systems

Two deep wells are used at LaSalle as the supply for potable and sanitary water and for makeup demineralizer water. Both wells were installed during construction of the station and draw water from depths greater than 1,600 feet. Based on total gallons pumped for years 2008 through 2012, the average pumping rate for Well #1 is 20.8 gpm and for Well #2 is 5.30 gpm. The water is stored in a 350,000 gallon tank prior to distribution.

6.2.2 Waste Systems

6.2.2.1 Liquid Radioactive Waste System

Liquid radwaste is stored for decay or concentrated to solid waste for controlled disposal at regulated storage sites. [UFSAR Sec 1.1, page 1.1-3]

The Liquid Radioactive Waste System, which serves both LaSalle units, collects, treats, stores, and disposes or recycles , with or without treatment as appropriate, all potentially radioactive liquid wastes produced by plant operations and maintenance. This system is capable of discharging directly into the cooling pond blowdown line by a batch process at a maximum discharge rate of 45 gpm, dependent on dilution calculations, as authorized by NPDES permit IL0048151 (Outfall E01).

However, LaSalle has voluntarily undertaken an approach to limit releases of radioactive species through the liquid pathway. In addition to the in-plant systems for processing liquids associated with boiling water reactor operations, the LaSalle Liquid Radioactive Waste System includes a vendor-provided Advanced Liquid Processing System (ALPS). The Liquid Radioactive Waste System is designed to recycle as much processed liquid as can be accommodated within the station water balance. Since 2000, no liquid radioactive waste effluents have been released through Outfall E01.

If treated waste water were to be not needed for recycle, the water would be sent to the discharge tank and held until a discharge batch is accumulated. Each batch would be sampled to verify that its activity level is within limits for discharge. The actual discharge to the lake blowdown line requires opening a keylock valve in accordance with written operating procedures, only after sampling. This assures that if radionuclide releases were necessary they would comply with the requirements of 10 CFR 20 and 10 CFR 50, Appendix I.

6.2.2.2 Sewage Treatment System

The potable and sanitary water system is supplied from two deep wells located on the station property. The potable and sanitary water system does not connect to any system that might discharge radioactive materials. LaSalle operates an onsite sewage treatment plant. Sewage treatment is provided by primary and secondary aerated lagoon cells. The effluent of the lagoon is normally treated by sand filtration, for total suspended solids reduction. Sewage treatment effluent is disinfected and then discharged into the cooling pond (Outfall B01) for eventual discharge to the Illinois River through Outfall 001 under NPDES permit IL0048151.

6.2.2.3 Other Systems

In addition to the Liquid Radioactive Waste and Sewage Treatment Systems, five other LaSalle systems discharge wastewaters to the Illinois River through Outfall 001 (Outfalls A01, C01, D01, F01 and I01). Outfall 001 also receives storm water runoff through Outfalls G01 and H01, as described in Section 6.2.3. Screen backwash and other intermittent discharges associated with the river makeup water intake are discharged to the Illinois River through Outfall 002.

6.2.3 Storm Water

The LaSalle plant is approximately 5 miles south of the Illinois River. The cooling pond is approximately 2 miles south of the Illinois River at its closest point. Natural drainage at the LaSalle plant is generally toward the cooling pond.

The plant area is divided into two zones, Zone I (north) and Zone II (south), which discharge to the North Site Runoff Outfall (G01) and South Site Runoff Outfall (H01), respectively. The plant

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areas to the northwest and south of Zones I and II are drained away by existing creeks and gullies.

Uncontaminated runoff from the north side of the plant flows through the north storm water retention pond and then discharges to the cooling pond discharge canal via Outfall G01. The following potential pollutant sources are located in Zone I:

- The Silt Dispersant Tank, which is dual walled and has a fill station with a spill collection system.
- The SH Chillers, which are enclosed package units containing ethylene glycol and are equipped with relief valves that discharge to overflow barrels situated on spill pallets.
- Salt used for road maintenance, which is stored inside to prevent salt from being dissolved and carried away by rain water.
- Oil-containing equipment associated with the independent spent fuel storage installation (ISFSI), which is stored inside the ISFSI building and enclosed by spill prevention berms.

Some of the storm drains on the plant's north side are routed through the Unit 2 Oil Separator, upstream of the north storm water retention pond.

Uncontaminated runoff from the south side of the plant flows through the south storm water retention pond and then discharges to the cooling pond discharge canal through Outfall H01. The following potential pollutant sources are located in Zone II:

- Aboveground chemical, gasoline, and diesel fuel storage tanks, which are dual walled or located within a secondary containment area.
- Loading and unloading operations, which take place within a bermed area or a drainage area that is routed to a process outfall, or employ drip pans at the point of connection.

Some of the storm drains on the plant's south side are routed through the Unit 1 Oil Separator, upstream of the south storm water retention pond. Runoff from the Exelon Generation Firing Range and associated berm, which are located on the LaSalle site property, also flows into the south storm water retention pond. Because some lead bullets are used at the firing range, best management practices (BMPs) for spent lead and potential contamination have been implemented.

The peripheral dike drainage ditch, which parallels the LaSalle cooling pond dikes, intercepts storm water runoff and cooling pond seepage at the downstream toe of the dikes. The drainage ditch discharges into Armstrong Run and three branches of the South Kickapoo Creek.

Stormwater runoff from the switchyard area flows east toward the cooling pond. A portion of the switchyard area is included in the Zone 1 drainage described above.

A storm water pollution prevention (SWPP) plan is maintained at LaSalle in accordance with NPDES permit IL0048151 Special Condition 8. The SWPP Plan identifies potential sources of pollutants that may be expected to affect storm water discharges associated with the industrial activity in the areas drained to permitted outfalls G01, H01, and 002. The plan also describes practices that are used to reduce pollutants in storm water discharges and assure compliance with applicable conditions of the NPDES permit. Areas having potential for spills of a regulated substance, such as oil, are further monitored under the LaSalle Spill Prevention Control and Countermeasure Plan.

The LaSalle cooling pond is managed to maintain a relatively constant water level. However, under certain transient conditions (e.g., an extreme weather event), the cooling pond water level may rise above design parameters. In such circumstances, discharges of storm water may

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occur at the auxiliary spillway rather than through Outfall 001 as a result of design requirements set forth in IDNR dam construction regulations. The LaSalle cooling pond auxiliary spillway is designed to relieve excess cooling pond water level by discharging the overflow to a branch of the South Kickapoo Creek.

6.3 Water Quality Standards and the Conditions of Water Resources in the Project Area

The IEPA implements Illinois water quality standards, which have their basis in the federal Clean Water Act (CWA), include general water quality standards (that apply regardless of water classification) and standards applicable to General Use waters. General water quality standards are described in Illinois Administrative Code (IAC) Title 35, Part 302, Subpart A, and include requirements for mixing zones, flows, temperature, and antidegradation.

Standards applicable to General Use waters are described in IAC Title 35, Part 302, Subpart B, and include those for radioactivity, dissolved oxygen, nutrients, toxic substances, and a range of chemical constituents. General Use standards protect water for aquatic life, wildlife, agricultural use, secondary contact use, and most industrial uses.

Through Section 303(d) of the CWA, the U.S. EPA requires states to identify impaired waters of the state; that is, those waters where the required pollution control measures are not sufficient to maintain applicable water quality standards. Water bodies on the CWA Section 303(d) impaired waters list are subject to a more proactive approach to pollution prevention and water quality management.

Finally, the IDNR is responsible for the protection of fish and aquatic life (515 ILCS 5 Fish and Aquatic Life Code), including protecting aquatic life from "waste, sewage, thermal effluent or any other pollutant [that] allows pollution of waters of the state..."

NPDES permit IL0048151 authorizes releases from seven LaSalle industrial wastewater sources (Outfalls A01 – F01 and I01) either to the cooling pond, which discharges through a blowdown line to the Illinois River (Outfall 001), or to the cooling pond blowdown line. Outfall 001 also receives storm water runoff through Outfalls G01 and H01. Screen backwash and other intermittent discharges associated with the river makeup water intake are discharged to the Illinois River through Outfall 002.

The following subsections in this section describe applicable standards and water quality requirements for the Illinois River, South Kickapoo Creek and Armstrong Run. Section 6.4 discusses the effect of permitted discharges.

6.3.1 Illinois River

The Illinois River is classified as General Use water by the IEPA Bureau of Water (IAC Title 35, Section 303.201). The NPDES permit imposes load and/or concentration limits on LaSalle effluents that must be maintained to meet all applicable standards. Parameters regulated by the LaSalle NPDES permit include total suspended solids, temperature, oil and grease, pH, carbonaceous biochemical oxygen demand, total residual chlorine/total residual oxidants, and zinc. The permit specifically prohibits discharges of certain contaminants, such as PCBs. LaSalle monitors the discharges and parameters and provides results to IEPA in monthly reports.

Under IAC Title 35, Section 302.102, a temperature mixing zone "must not contain more than 25 percent of the cross-sectional area or volume of flow of a stream." In Special Condition 3 of NPDES permit IL0048151, IEPA has determined that LaSalle meets this criteria as well as the thermal water quality standard in Title 35, Section 302.211. However, LaSalle is required to monitor and report the flow and temperature of its blowdown discharge.

In accordance with Special Condition 3 of NPDES permit IL0048151 and IAC Title 35, Section 302.211, the maximum temperature rise of a discharge above natural temperature must not exceed 5°F. In addition, the water temperature at representative locations in the main river must not exceed the maximum limits in the following table during more than one percent of the hours in the 12-month period ending with any month. Moreover, at no time is the water temperature at such locations to exceed the maximum limits in the following table by more than 3°F.

Illinois River Temperature Limits

Temperature	December - March	April-November
°F	60	90

Thermal discharges are limited to less than 0.5 billion BTUs per hour in accordance with the IAC Title 35, Section 302.211(f) regulations. Normal daily and seasonal temperature fluctuations in the river must be maintained.

LaSalle reduces blowdown flow or makes other operational modifications, when necessary, to maintain the mixing zone temperature within the NPDES permit limits. There are provisions for a limited number of hours per year when minor variances or excursions in the flow and thermal limits specified in the NPDES permit are allowed. These excursion hours usually occur due to a rapid change in Illinois River ambient temperature or due to a change in wind direction on the cooling pond which can blow the warmest surface water down to the power plant intake. During summer months, LaSalle implements an Extreme Heat Implementation Plan that provides for monitoring of plant and environmental conditions to alert plant personnel when use of excursion hours is likely pending.

The stream segment (IL_D-23) of the Illinois River receiving the discharge from LaSalle Outfall 001 is identified in the proposed 2014 *Illinois Integrated Water Quality Report and Section 303(d) List* (IEPA Undated) as impaired for fish consumption and primary contact due to the potential causes listed in the table below.

Potential causes	Uses Impaired
Mercury, PCBs, Fecal Coliform,	Fish Consumption, Primary Contact

Based on the IDNR's Biological Stream Rating Mapping Tool, the Illinois River is not a biologically significant stream at the LaSalle outfall location. The Illinois River is not assigned a biological diversity rating or an integrity rating at this location. The river at this location is designated for enhanced dissolved oxygen protection pursuant to IAC Title 35, Part 302 Appendix D. Dissolved oxygen concentrations in these streams/stream segments must be not less than 5.0 mg/L at any time during the period of March through July and not less than 4.0 mg/L at any time during the period of August through February. NPDES permit IL0048151 specifies limits on carbonaceous biochemical oxygen demand in the LaSalle sewage treatment plant effluent (Outfall B01). Special Condition 3 of the permit states that LaSalle meets the mixing criteria for thermal discharges pursuant to 35 IAC 302.102, however, the station must monitor and report discharge flow and temperature.

6.3.2 South Kickapoo Creek and Armstrong Run

South Kickapoo Creek, a tributary of the Illinois River, receives discharges from the perimeter dike drainage ditch, and may receive discharges from the cooling pond auxiliary spillway in certain extreme circumstances. South Kickapoo Creek flows to the northwest from LaSalle, and discharges into the Illinois River from the south 0.5 mile downstream from the river screen house. Armstrong Run, which also receives discharges from the perimeter dike drainage ditch, flows northeast from LaSalle and discharges to the Illinois River 4.5 miles upstream of the river screen house. These stream segments are classified as General Use waters by the IEPA Bureau of Water (IAC Title 35, Section 303.201), but neither is on the 303 (d) list of impaired waters, and neither has a biological stream characterization.

6.4 LaSalle Surface Water Use

As described in Section 6.2.1, LaSalle withdraws makeup water from the Illinois River to replace evaporation and seepage losses and blowdown discharges from the cooling pond. Therefore, the operation of LaSalle affects this water source, the use of which is regulated by the State of Illinois.

The rate of makeup water pumping varies depending on the plant operating load and weather conditions and is aimed at maintaining a constant level in the cooling pond. During normal makeup periods, the cooling pond makeup rate is 30,000 gpm with one pump operating. Maximum makeup withdrawal would be 60,000 gpm with two pumps operating. Operation of three pumps at full flow would be for emergency purposes only. The maximum blowdown rate is 90,000 gpm but plant operating procedures limit the flow to not more than 58,000 gpm without a manual override (e.g., to address a high lake level caused by excess precipitation).

The U.S. Geological Survey maintains a permanent gaging station on the Illinois River downstream of LaSalle at Marseilles, Illinois. Annual mean flow measurements for the period of record (1920-2012) for that station average 10,760 cfs, or more than 4.8 million gpm (USGS 2013). Consumptive water use (makeup withdrawals less the water returned to the river as blowdown) of approximately 21,500 gpm accounts for less than 0.5 percent of the average annual mean river flow. Therefore, the river flow would rarely, if ever, be so low as to affect makeup water pumping to the cooling pond.

In NPDES permit IL0048151, Special Condition 15, the IEPA finds that the LaSalle closed-cycle recirculating cooling system is equivalent to Best Technology Available for cooling water intake structures to prevent/minimize impingement mortality in accordance with the Best Professional Judgment provisions of 40 CFR 125.3 because it allows the facility to only withdraw the amount of water necessary to maintain the cooling pond level rather than the entire volume used for cooling of the plant condensers. Special Condition 15 also identifies information that Exelon must provide to IEPA to support a Best Professional Judgment Review of potential impacts of cooling water intake structure operations for compliance with Section 316(b) of the CWA.

The expected chemical composition of the LaSalle cooling pond discharge (Outfall 001) is described in the 2011 application for renewal of NPDES permit IL0048151. A list of water treatment additives used at the station was also included in the 2011 renewal application. Permit Special Condition 9, which was finalized July 5, 2013, authorizes use of those additives. The use of new additives, changes in the additives previously approved and increases in the feed rate or quantity of the additives used at LaSalle require IEPA approval. The pH of the discharge to the river is monitored and treated as necessary to meet the limitations specified in NPDES permit IL0048151, Special Condition 2.

Renewal by the NRC of the LaSalle Operating Licenses would not change plant discharges or pollutant loads to the Illinois River.

6.5 Monitoring Programs

6.5.1 Environmental Protection Plan

Exelon carries out the environmental monitoring programs described in the Environmental Protection Plan that is incorporated into the NRC operating licenses for LaSalle Units 1 and 2. The Environmental Protection Plan incorporates the NPDES permit by reference. Therefore, monitoring of the aquatic environment consists of the monitoring specified in the NPDES permit.

6.5.2 Radioactive Monitoring in Surface and Groundwater

Radiological Environmental Monitoring Program

LaSalle has a radiological environmental monitoring program that was initiated in 1982 and includes routine sampling and analysis of surface and ground water for radioactive constituents that could originate from plant operations. One objective of this program is to provide data on measurable levels of radiation and radioactive material released from the plant. This is accomplished through long-term monitoring of certain environmental media in the off-site vicinity of the station, including surface water and groundwater. Surface water and groundwater samples (two locations for each) are tested for the presence of specific gamma emitting radionuclides that may be produced by LaSalle operations, as well as for tritium, which is produced both naturally in the environment and in the reactor coolant system. The surface water samples are also tested for gross beta emissions.

During 2012, no gamma-emitting radionuclides that may be produced by LaSalle operations were detected in groundwater or surface water samples, and tritium activities, which ranged from 183 to 1,150 picoCuries per liter (pCi/L), were well below the U.S. Environmental Protection Agency (USEPA) drinking water standard (20,000 pCi/L). Gross beta emissions in surface water samples ranged from 5.9 to 10.4 pCi/L during 2012, which is consistent with levels detected in previous years.

Fleetwide Assessment

In 2006, Exelon began a fleetwide initiative, apart from ongoing Radiological Environmental Monitoring Programs, to determine whether groundwater at or near its nuclear stations was being adversely affected by releases of radionuclides. As part of the initiative, Exelon reviewed information about historical releases and evaluated information about structures, components, and areas at LaSalle that have potential to release tritium or other radioactive liquids. Based on the results, groundwater and surface water sampling locations were identified for further investigation. Exelon collected samples at these locations in May 2006. One groundwater sample contained tritium that exceeded 200 pCi/L; the lower limit of detection, but at 1,280 pCi/L, it did not approach the USEPA drinking water standard (20,000 pCi/L). Tritium was the only radionuclide detected in groundwater at LaSalle during May 2006.

The tritium detected in LaSalle groundwater was localized to the area around one monitoring well, and its presence was judged to have most likely been from a historical release associated with a Unit 2 Cycled Condensate System storage tank overflow in 2001. Due to the hydrogeologic conditions in the area, the tritiated water was not expected to migrate very far laterally from the monitoring well location. The assessment concluded there was no indication that tritium-contaminated groundwater was migrating off site.

Tritium was detected in two surface water samples in May 2006, one from the intake canal and one from the north stormwater retention pond. The assessment concluded the likely source of the tritium detections was elevated tritium concentrations in the Illinois River that did not originate from LaSalle.

Results of the 2006 fleetwide initiative were used to develop a corporate Radiological Groundwater Protection Program (RGPP) that samples groundwater and surface water at all Exelon nuclear stations annually for concentrations of radionuclides. Results of RGPP monitoring for LaSalle are reported each year in an appendix to the LaSalle Annual Radiological Environmental Operating Report.

2010 Unit 1 Cycled Condensate System Storage Tank Leak

In 2010, a leak from the Unit 1 Cycled Condensate System (CY) storage tank was identified and remediated. Because the resultant tritium plume was dispersing with groundwater flow, a recovery well was installed to control the migration of the plume. The well became operational in October 2012. Two monitoring wells were installed in June 2012 and added to the RGPP monitoring system to further evaluate the tritium plume in the area of the tank.

During 2012, levels of tritium were detected at concentrations greater than the lower limit of detection in 7 of 18 groundwater monitoring locations. The tritium concentrations ranged from less than the lower limit of detection to 379,000 ± 200 pCi/L. Elevated tritium levels (>200 pCi/L) observed are associated with the 2010 Unit 1 CY storage tank leak and the 2001 Unit 2 CY storage tank release. To date, no tritium has migrated offsite, and tritium migration offsite is not expected.

6.6 Antidegradation Assessment

The IAC Title 35, Part 302, Water Quality Standards, requires IEPA to assess on a case-by-case basis any activity requiring a CWA Section 401 certification for compliance with the antidegradation standard (§ 302.105(c)(2)). Further, IEPA's assessment is required to consider the fate and effect of any parameters proposed for increased pollutant loading, and to assure that water quality standards will not be exceeded, all existing uses will be fully protected, all reasonable measures to avoid or minimize the extent of the proposed increase in pollutant loading have been incorporated, and the activity that results in increased pollutant loading will benefit the community at large.

As previously stated in this application, NRC renewal of the LaSalle operating licenses would not alter discharges or discharge pollutant loads from the LaSalle units during the extended operating terms, and no construction is planned in connection with the license renewals. In addition, LaSalle has operated since 1984, and will continue to operate subject to the IEPA NPDES permit IL0048151, as it may be renewed or modified from time to time, as well as any agreements pertaining to water quality between the Station and IDNR.

Compliance with the discharge limits and surveillance requirements specified in NPDES Permit IL0048151 assures that LaSalle operations will protect existing uses of the Illinois River and will not result in exceedances of numeric or narrative water quality standards. Exelon must periodically apply for renewal of the NPDES permit. Compliance with each renewed NPDES permit provides additional assurance that discharges from LaSalle will not degrade the Illinois River.

In summary, the proposed renewal of the LaSalle operating licenses would comply with the antidegradation criteria related to 401 certification reviews by IEPA because no increase to pollutant loading would be associated with NRC renewal of the LaSalle operating licenses and because LaSalle would remain subject to the NPDES permit requirements as well as IDNR regulations and agreements during the license renewal terms.

References

IEPA Undated. Illinois Environmental Protection Agency, Illinois Integrated Water Quality Report and Section 303(d) List, 2014. Expected to be published May 2014. Accessed at http://www.epa.state.il.us/water/tmdl/303-appendix/2014/appendix-b2.pdf.

USGS 2013. U.S. Geological Survey, Water-resources data for the United States, Water Year 2012: U.S. Geological Survey Water-Data Report WDR-US-2012, site 05543500. Accessed at http://wdr.water.usgs.gov/wy2012/pdfs/05543500.2012.pdf

7.0 LaSalle County Station Adjacent Property Owners

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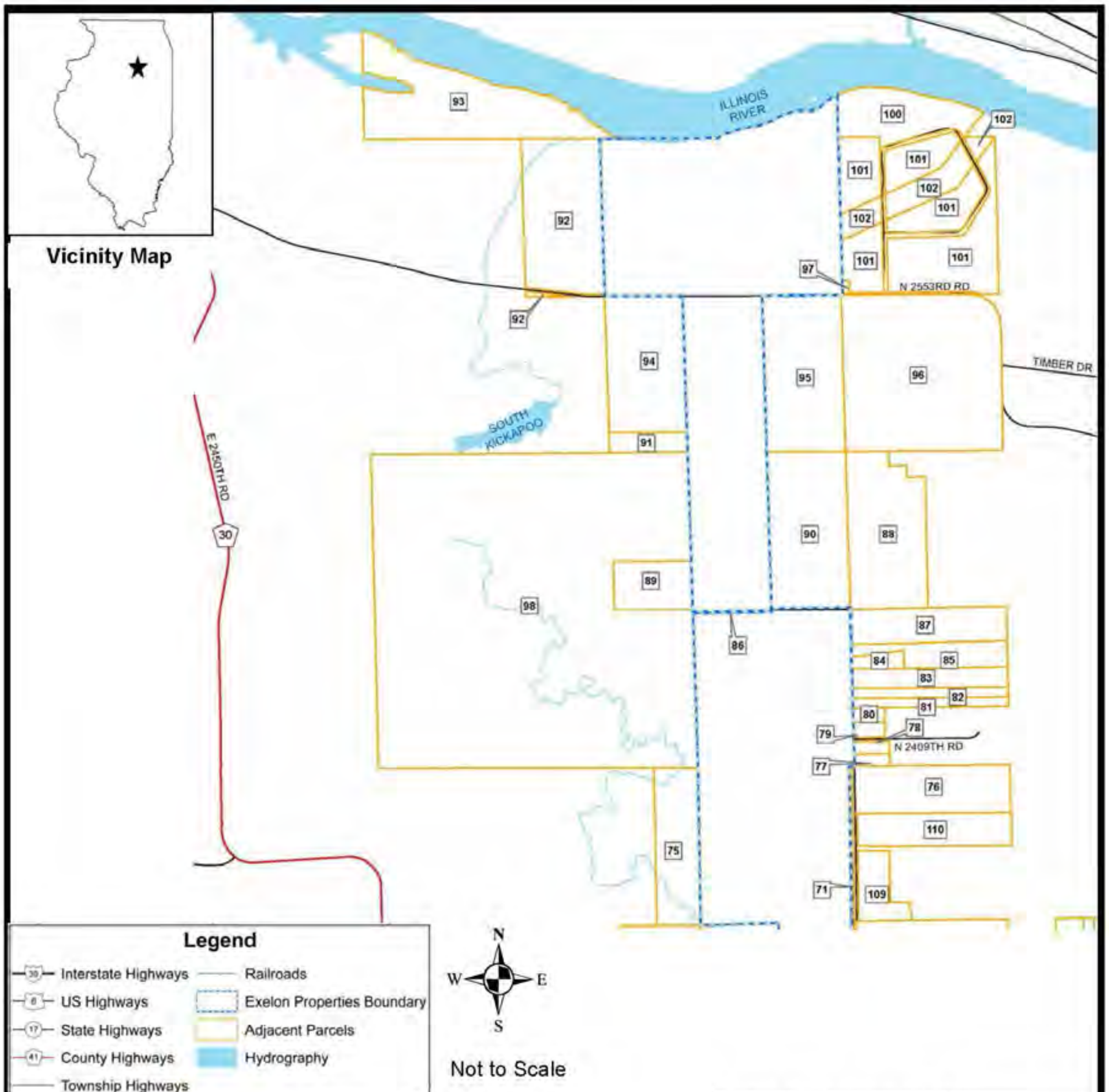

LIST OF ADJACENT PROPERTY OWNERS

NO.	NAME	ADDRESS
1.	See Attached Sheets	
2.		
3.		
4.		

PROJECT DESCRIPTION

LaSalle County Station
Operating License Renewal

LOCATION:
LaSalle County Station
Marseilles, IL

NCR FORM 426
08 AUG 02

SHEET 1 OF 4

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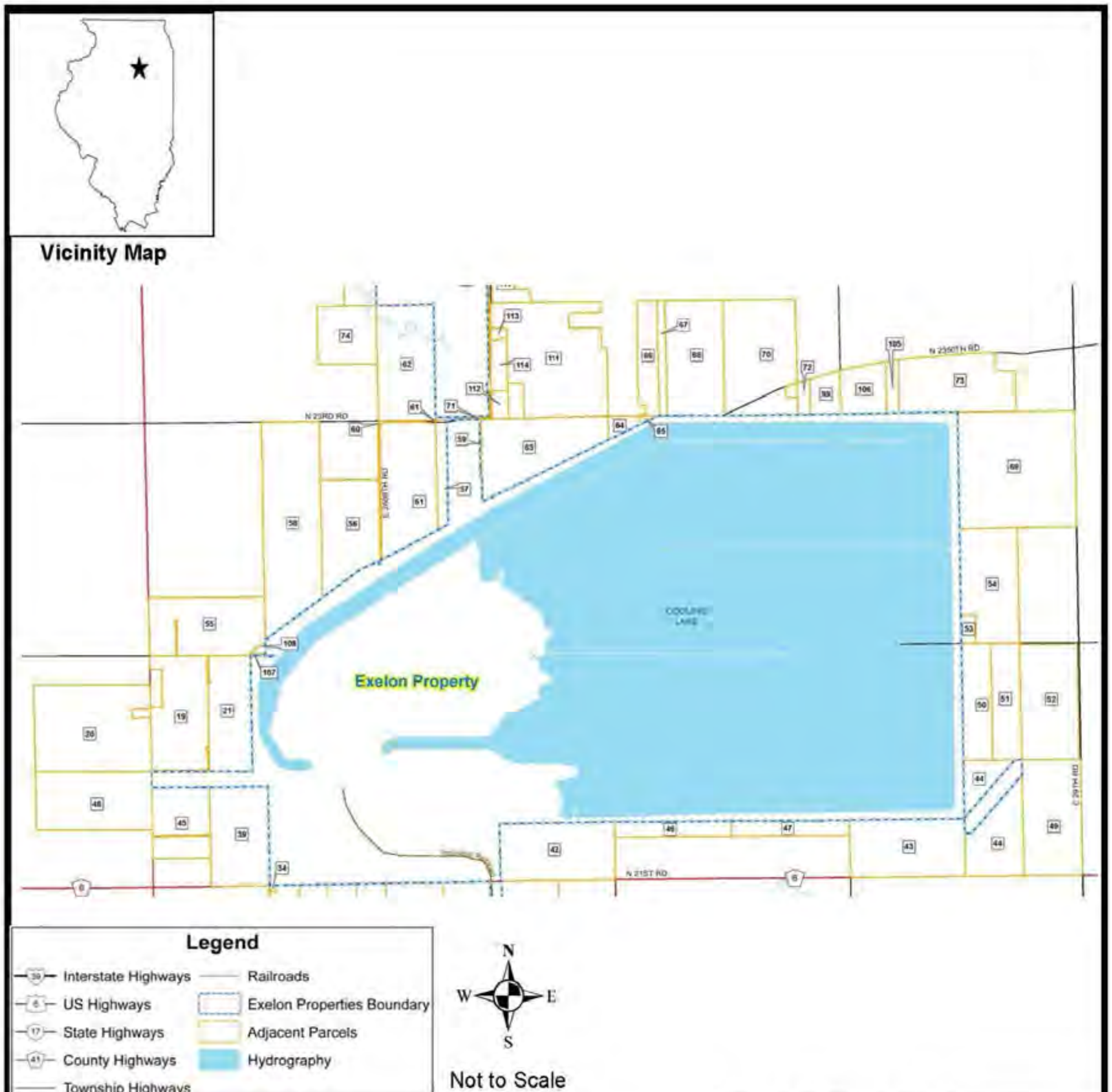

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2.		
3.		
4.		

PROJECT DESCRIPTION

LaSalle County Station
Operating License Renewal

LOCATION:
LaSalle County Station
Marseilles, IL

NCR FORM 426
08 AUG 02

SHEET 2 OF 4

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LIST OF ADJACENT PROPERTY OWNERS			PROJECT DESCRIPTION
NO.	NAME	ADDRESS	LaSalle County Station Operating License Renewal
1.	See Attached Sheets		
2.			LOCATION: LaSalle County Station Marseilles, IL
3.			
4.			

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SHEET 3 OF 4

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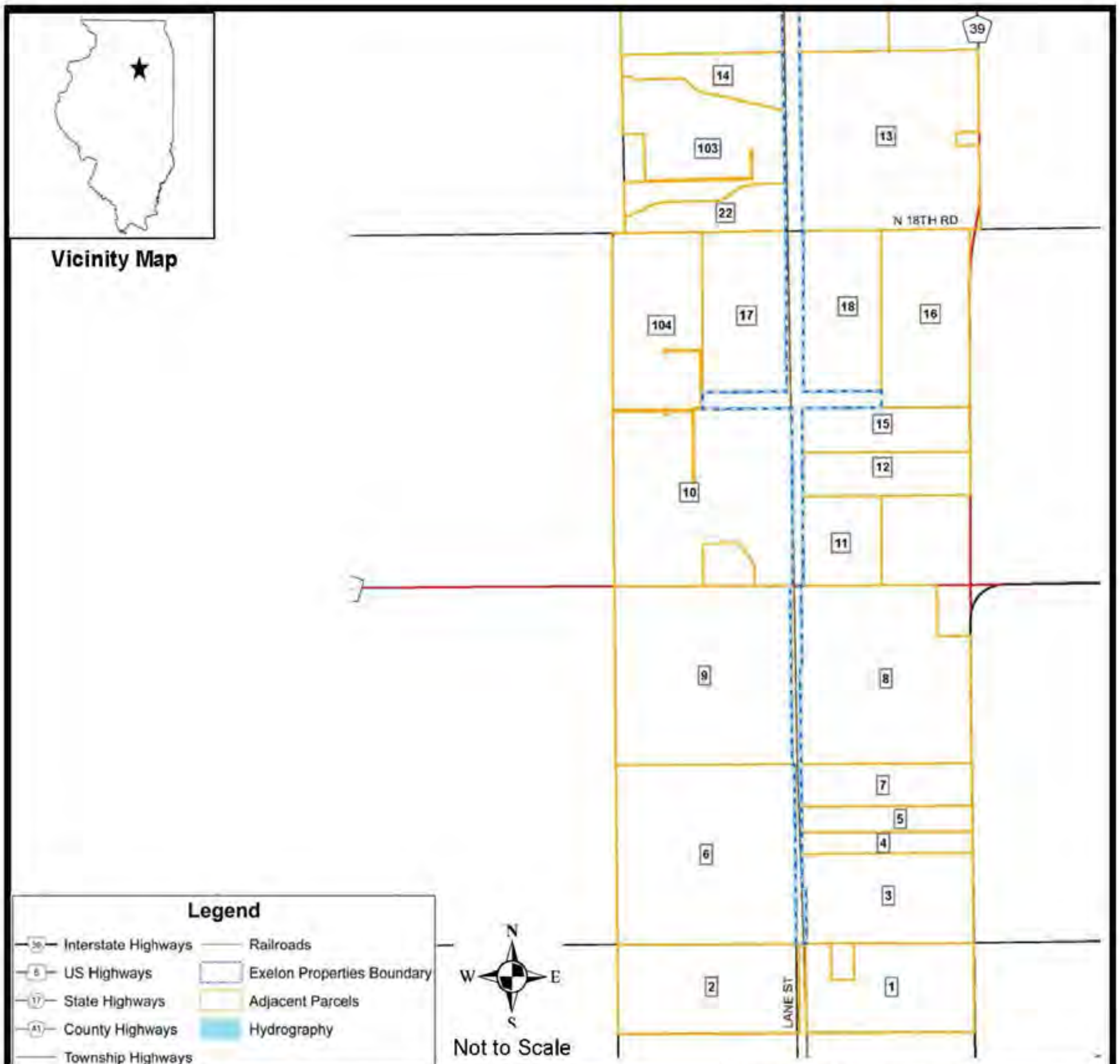

LIST OF ADJACENT PROPERTY OWNERS

NO.	NAME	ADDRESS
1.	See Attached Sheets	
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4.		

PROJECT DESCRIPTION

LaSalle County Station
Operating License Renewal

LOCATION:
LaSalle County Station
Marseilles, IL

NCR FORM 426
08 AUG 02

SHEET 4 OF 4

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Exelon LaSalle County Station License Renewal Adjoining Property Owners

Site	PIN	Owner	Property Address	Mailing Address (if different)
1	30-16-201-005	GRAINCO FS, INC		3107 N HWY 23 OTTAWA IL 61350
2	30-16-100-007	ALLEN TWP COM CON SCHL #65		C/O JANICE EMM 1522 E 28TH RD RANSOM IL 60470
3	30-09-400-004	WIDMAN, SUE		7926 STEWART DARIEN IL 60559
4	30-09-400-007	WIDMAN, CARRIE R		3846 WEST 109TH ST CHICAGO IL 60655
5	30-09-400-006	WIDMAN, RYAN J		1539 E 29TH RD RANSOM IL 60470
6	30-09-300-001	WALDVOGEL, DONALD J TRUSTEE		#103029 26779 N 02900 E RD DWIGHT IL 60420
7	30-09-400-005	WIDMAN, CHERYL L		44 STANTON PL STREATOR IL 61364
8	30-09-200-003	OSTERDOCK, DELORES M TRUST		2005 S CHURCH ST STREATOR IL 61364-3829
9	30-09-100-001	REDMANN, CLYDE/ MARIE ETAL TRUST		5970 NE 18TH TERR FT LAUDERDALE FL 33308
10	30-04-300-007	ALLEN TWP COM CON SD#65		C/O JANICE EMM 1522 E 28TH RD RANSOM IL 61364
11	30-04-400-004	OSTERDOCK, DELORES M TRUST		2005 S CHURCH ST STREATOR IL 61364-3829
12	30-04-400-003	ROSS, JAMES/ MARY		2686 N 19TH RD RANSOM IL 60470
13	25-33-400-001	CORRIGAN, ARTHUR J-MARY		1810 E 27TH RD RANSOM IL 60470
14	25-33-300-001	O LAUGHLIN, GERALDINE C		6149 N KNOX AVE CHICAGO IL 60601
15	30-04-400-002	ROSS, WILLIAM J		1688 N IL ST RT 170 RANSOM IL 60470
16	30-04-200-003	QUAKA, P JANIE		738 N 1850TH RD TONICA IL 61370
17	30-04-100-002	ALLEN TWP LAND COMMISNRS		C/O JANICE EMM 1522 E 28TH RD RANSOM IL 60470
18	30-04-200-002	HOUSER, CONNIE / TRAINOR, PEGGY		2007 N SEDGWICK ST UNIT 706 CHICAGO IL 60614-4852
19	25-17-100-005	DAHLKE, RALPH W		439 E GREEN OAKS CT #1 ADDISON IL 60101
20	25-18-200-005	PETGES, KAREN L / JAMES M TTEE	E 25TH RD MARSEILLES IL 61341	THE CHARLES PETGES FAMILY TRUST 1207 ILLINI DR LOCKPORT IL 60441

Site	PIN	Owner	Property Address	Mailing Address (if different)
21	25-17-100-007	GAGE FARMS INC		2474 N 23RD RD MARSEILLES IL 61341
22	25-33-300-003	O LAUGHLIN, GERALDINE C TTEE		6149 N KNOX AVE CHICAGO IL 60601
23	25-33-100-001	HOUSER, CONNIE / TRAINOR, PEGGY		2007 N SEDWICK ST UNIT 706 CHICAGO IL 60614-4852
24	25-33-200-001	MYERS, JEANETTE TTEE ETAL		18439 E 2800 NORTH RD ODELL FL 60460
25	25-28-400-001	O'LAUGHLIN, RICHARD J ETAL	N 19TH / E 27TH ROADS RANSOM IL 60470	C/O O'LAUGHLIN FARM 14 BROOK FARM COURT HUNT VALLEY MA 21030
26	25-28-300-001	FIRST NATIONAL BANK TRUST		COLLEEN UGOLINI ETAL 2021 E 27TH RD SENECA IL 61360
27	25-28-200-002	O'LAUGHLIN, RICHARD J ETAL	E 27TH RD RANSOM IL 60470	C/O O'LAUGHLIN FARM 14 BROOK FARM COURT HUNT VALLEY MA 21030
28	25-28-100-002	O LAUGHLIN, MICHAEL FREDRICK		HOUSE ONE BELLEVIEW GARDEN 5 BELLEVIEW DR REPULSE BAY
29	25-28-200-001	UGOLINI, JOSEPH / BETH TTEE		2021 E 27TH RD SENECA IL 61360
30	25-21-300-004	FIRST NATIONAL BANK TR 1688		COLLEEN UGOLINI ETAL 2021 E 27TH RD SENECA IL 61360
31	25-21-400-001	FIRST NATIONAL BANK TRUST	2021 E 27TH RD SENECA IL 61360	COLLEEN UGOLINI ETAL 2021 E 27TH RD SENECA IL 61360
32	25-21-200-001	DANIELSON, JACQUELYN ETAL TTEE		C/O HERTZ FARM MANAGEMENT INC PO BOX 500 NEVADA IA 50201
33	25-20-100-006	PATTERSON, WILLIAM / LOUISE	2548 N 21ST	302 S LASALLE ST RANSOM IL 60470
34	25-20-200-001	DAVIS, MICHAEL/VIVIAN	2534 N 21ST RD MARSEILLES IL 61341	2534 N 21ST RD MARSEILLES IL 61341
35	25-20-200-004	WIDMAN, JEAN M		2569 N 19TH RD RANSOM IL 60470
36	25-20-200-005	WIDMAN, MARK J		2569 N 19TH RD RANSOM IL 60470
37	25-20-200-006	WIDMAN, JOHN R/ KELLEE J		2568 N 19TH RD RANSOM IL 60470
38	25-20-200-003	MAIER, CHARLES/ BRENDA	N 21ST RD & E 26TH RD SENECA IL 61360	2203 E 29TH RD SENECA IL 61360
39	25-17-300-004	WICKS, ANNA M / EVANS, JEAN WICKS- TTEES		KERVYNE L WICKS RESIDUARY TRUST 305 OAK RIDGE OTTAWA IL 61350

Site	PIN	Owner	Property Address	Mailing Address (if different)
40	25-21-100-001	DANIELSON, JACQUELYN ETAL TTEE		C/O HERTZ FARM MANAGEMENT INC PO BOX 500 NEVADA IA 50201
41	25-21-100-002	DANIELSON, JACQUELYN ETAL TTEE		C/O HERTZ FARM MANAGEMENT INC PO BOX 500 NEVADA IA 50201
42	25-16-400-001	O LAUGHLIN, MICHAEL		HOUSE ONE BELLEVIEW GARDEN 5 BELLEVIEW DR REPULSE BAY
43	25-14-300-003	KAVANAUGH, GARY F		876 MANCHESTER CT WILMINGTON IL 60481-2328
44	25-14-400-001	DANIELSON, JACQUELYN ETAL TTEE		C/O HERTZ FARM MANAGEMENT INC PO BOX 500 NEVADA IA 50201
45	25-17-300-005	WICKS, ANNA M / EVANS, JEAN WICKS- TTEES		KERVYNE L WICKS RESIDUARY TRUST 305 OAK RIDGE OTTAWA IL 61350
46	25-15-300-011	O LAUGHLIN, MICHAEL		HOUSE ONE BELLEVIEW GARDEN 5 BELLEVIEW DR REPULSE BAY
47	25-15-400-005	KAVANAUGH, GARY F		876 MANCHESTER CT WILMINGTON IL 60481-2328
48	25-18-400-001	CARR, PHILIP ETAL		509 5TH AVE OTTAWA IL 60350
49	25-14-400-002	BEDEKER, DAVID/DARLENE		2175 E 29TH RD SENECA IL 61360
50	25-14-200-003	PETGES, SCOTT		540 E OAK GROVE ST JUNEAU WI 53039
51	25-14-200-004	PETGES, JAMES M		2208 PEBBLE BEACH DR PLAINFIELD IL 60544
52	25-14-200-002	BEDEKER, DAVID W-DARLNE	2175 N IL ST RT 170 SENECA IL 61360	2175 E 29TH RD SENECA IL 61360
53	25-11-400-005	DEPT OF NATURAL RESOURCES		CONNIE WAGNER/OFFICE REALTY ONE NATURAL RESOURCES WAY SPRINGFIELD IL 62702-1271
54	25-11-400-004	WALTER, DEAN ETAL		4076 E 20TH RD SHERIDAN IL 60551
55	25-08-300-003	GAGE FARMS INC	N 22RD	2474 N 23RD RD MARSEILLES IL 61341
56	25-08-200-003	VAN CLEAVE, THOMAS J		PO BOX 632 403 HOSSACK ST SENECA IL 61360
57	25-09-100-003	MITCHELL, LAWRENCE/ CONNIE		2882 E 2575TH RD MARSEILLES IL 61341
58	25-08-200-001	GLEIM, JOHN D		2179 E 21ST RD GRAND RIDGE IL 61325
59	25-09-100-005	CHICAGO TITLE & TRUST CO		TRUST #1098157 171 N CLARK ST CHICAGO IL 60601-3294

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Site	PIN	Owner	Property Address	Mailing Address (if different)
60	25-09-100-001	VAN CLEAVE, WILLIAM/DORENE		403 HOSSACK ST SENECA IL 61360
61	25-09-100-002	VAN CLEAVE, WILLIAM/DORENE		403 HOSSACK ST SENECA IL 61360
62	25-04-300-001	DEPT OF NATURAL RESOURCES		CONNIE WAGNER/OFFICE REALTY ONE NATURAL RESOURCES WAY SPRINGFIELD IL 62702-1271
63	25-09-200-001	MITCHELL, LAWRENCE/ CONNIE		2882 E 2575TH RD MARSEILLES IL 61341
64	25-10-100-002	MUSSER, MICHAEL/TERESA	2710 N 23RD RD MARSEILLES IL 61341	2710 N 23RD RD MARSEILLES IL 61341
65	25-10-100-003	O'BRIEN, WINSTON/CAROL	23RD RD MARSEILLES IL 61341	PO BOX 57 SENECA IL 61360
66	25-03-300-006	NEUENDORF, PATRICA TRUST	2721 N 23RD RD MARSEILLES IL 61341	2721 N 23RD RD MARSEILLES IL 61341
67	25-03-300-004	JACKSON, SHERWOOD L		3332 E 29TH RD SENECA IL 61360
68	25-03-300-005	JACKSON, SHERWOOD L		3332 E 29TH RD SENECA IL 61360
69	25-11-200-001	KILLELEA, J NESSINGER H		4800 HEATHERSTONE RD BETTENDORF IA 52722
70	25-03-400-004	HAUSKEN FAMILY FARM LLC		C/O KENNETH D HAUSKEN MANAGER 450 JEFFERSON ST MARSEILLES IL 61341
71	25-04-100-003	CHICAGO TITLE & TRUST CO		TRUST# 1098158 171 N CLARK ST CHICAGO IL 60601-3294
72	25-03-400-006	CATO, SAMUEL D	N 23RD RD MARSEILLES IL 61341	115 N MAIN ST SENECA IL 61360
73	25-02-300-009	GAGE FARMS INC		2474 N 23RD RD MARSEILLES IL 61341
74	25-05-400-002	DEPT OF NATURAL RESOURCES		CONNIE WAGNER/OFFICE REALTY ONE NATURAL RESOURCES WAY SPRINGFIELD IL 62702-1271
75	25-05-200-007	DEPT OF NATURAL RESOURCES		CONNIE WAGNER/OFFICE REALTY ONE NATURAL RESOURCES WAY SPRINGFIELD IL 62702-1271
76	25-04-200-002	BIANCHINI, DELFO / FRANCINE TTEE	2400 E 2659TH RD MARSEILLES IL 61341	1520 TYRELL AVE PARK RIDGE IL 60068
77	20-33-400-015	GRIFFITHS, JIMMIE W/ DANIELLE	2402 E 2659TH RD MARSEILLES IL 61341	2402 E 2659TH RD MARSEILLES IL 61341
78	20-33-400-014	BARTELMEY, THEODORE/ SHERYL	2662 N 2409TH RD MARSEILLES IL 61341	2662 N 2409TH RD MARSEILLES IL 61341
79	20-33-400-011	GOULOOZE, LEONARD/ SHARON	2412 E 2659TH RD MARSEILLES IL 61341	2412 E 2659TH RD MARSEILLES IL 61341

Site	PIN	Owner	Property Address	Mailing Address (if different)
80	20-33-400-010	SMITH, CARRIE MERLE-		C/O PAUL SMITH 1487 EAGLES LANDING NORTH MANTENO IL 60950
81	20-33-400-009	GALLICK, JEFF/EDNA	2420 E 2659TH RD MARSEILLES IL 61341	2420 E 2659TH RD MARSEILLES IL 61341
82	20-33-400-008	ERICKSON, GARY/CYNTHIA	2422 E 2659TH RD MARSEILLES IL 61341	2422 N 2659TH RD MARSEILLES IL 61341
83	20-33-400-007	BALAZIC, STEVE / HAAS, DONNA	2428 E 2659TH RD MARSEILLES IL 61341	2428 E 2659TH RD MARSEILLES IL 61341
84	20-33-400-022	4919 TRUSTEE	2446 E 2659TH RD MARSEILLES IL 61341	DONALD PODGORNY 2446 TRUST 2446 E 2659TH RD MARSEILLES IL 61341
85	20-33-400-021	OLD SECOND NATIONAL BANK	2488 E 2659TH RD MARSEILLES IL 61341	37 S RIVER ST AURORA IL 60506
86	20-33-300-002	CHICAGO TITLE & TRUST CO		TRUST #1098159 171 N CLARK ST CHICAGO IL 60601-3294
87	20-33-400-020	OSBORNE, HARRIET	2450 E 2659TH RD MARSEILLES IL 61341	2450 E 2659TH RD MARSEILLES IL 61341
88	20-33-200-005	OSBORNE, HARRIET M	MARSEILLES IL 61341	2450 E 2659TH RD MARSEILLES IL 61341
89	20-32-200-001	DEPT OF NATURAL RESOURCES		CONNIE WAGNER/OFFICE REALTY ONE NATURAL RESOURCES WAY SPRINGFIELD IL 62702-1271
90	20-33-100-005	HALL, JOSEPH M / TRIVA DAWN-SCHYL TTEE	2474 E 2659TH RD MARSEILLES IL 61341	HALL PERSONAL TRUST 51 MUIRFIELD CIRCLE WHEATON IL 60189
91	20-29-400-005	DEPT OF NATURAL RESOURCES		CONNIE WAGNER/OFFICE REALTY ONE NATURAL RESOURCES WAY SPRINGFIELD IL 62702-1271
92	20-29-200-001	PIONEER VALLEY SPORTSMANS ASSOCIATION	2573 2553RD RD MARSEILLES IL 61341	PO BOX 337 WHEATON IL 60187
93	20-20-300-002	BRUNO, JOSEPH M - JUANITA ETAL		C/O MATTHEW BRUNO 2507 N 2553RD RD MARSEILLES IL 61341
94	20-29-400-003	DEPT OF NATURAL RESOURCES		CONNIE WAGNER/OFFICE REALTY ONE NATURAL RESOURCES WAY SPRINGFIELD IL 62702-1271
95	20-28-300-002	COYLE, RALPH/APRIL	2626 N 2553RD RD MARSEILLES IL 61341	2626 N 2553RD RD MARSEILLES IL 61341
96	20-28-400-002	COYLE, RALPH/APRIL		2626 N 2553RD RD MARSEILLES IL 61341

Site	PIN	Owner	Property Address	Mailing Address (if different)
97	20-28-200-024	CITY OF MARSEILLES		209 LINCOLN ST MARSEILLES IL 61341
98	20-32-100-002	DEPT OF NATURAL RESOURCES		CONNIE WAGNER/OFFICE REALTY ONE NATURAL RESOURCES WAY SPRINGFIELD IL 62702-1271
99	25-03-400-007	PBJM SQUARED LLC	2786 N 23RD RD MARSEILLES IL	C/O BRUCE BARR 815 FREMONT AVE MORRIS IL 60450
100	20-21-400-018	FIRST NAT'L BANK OF JOLIET	FOYLE ACRE DR MARSEILLES IL 61341	TRUST 4142 & 4216 C/O N. GENE BRISCOE MINOOKA IL 60447
101	20-28-200-023	FIRST NAT'L BANK OF JOLIET	FOYLE ACRE DR MARSEILLES IL 61341	TRUST 4142 & 4216 C/O N. GENE BRISCOE MINOOKA IL 60447
102	20-28-200-002	COMMONWEALTH EDISON CO		PO BOX 767 TAX DEPT CHICAGO IL 60690
103	25-33-300-007	PLUTH, KAREN L TTEE ETAL		1207 ILLINI DR LOCKPORT IL 60441
104	30-04-100-004	SAMPSON, JANICE / BRIAN / SALLY TTEE		118 BARRINGTON PL MORTON IL 61550
105	25-02-300-014	TERRY, JUSTIN / HEATHER	N 23RD RD MARSEILLES IL 61341	2825 N 2350TH RD SENECA IL 63180
106	25-02-300-013	PBJM SQUARED LLC	2786 N 23RD RD MARSEILLES IL	C/O BRUCE BARR 815 FREMONT AVE MORRIS IL 60450

8. Legal Description

The following is a summary legal description of the property that is the subject of this application, without metes and bounds:

Parts of sections 21, 28, 29, and 33, Township 33N, Range 5E, 3rd principal meridian; and Parts of sections 4, 8, 9, 10, 11, 14, 15, 16, and 17, Township 32N, Range 5E, 3rd principal meridian.

Attachment 1
Illinois EPA NPDES Permit Number IL0048151
for LaSalle County Station

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 • (217) 782-2829
PAT QUINN, GOVERNOR LISA BONNETT, DIRECTOR

217/782-0610

July 5, 2013

Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, Illinois 60555

Re: Exelon Generation Company, LLC
LaSalle County Generating Station
NPDES Permit No. IL0048151
Final Permit

Gentlemen:

Attached is the final NPDES Permit for your discharge. The Permit as issued covers discharge limitations, monitoring, and reporting requirements. Failure to meet any portion of the Permit could result in civil and/or criminal penalties. The Illinois Environmental Protection Agency is ready and willing to assist you in interpreting any of the conditions of the Permit as they relate specifically to your discharge.

The Agency received your letter dated June 20, 2013 regarding the draft NPDES permit. Based on the information provided, the Agency has the following response.

1. Special Condition 3D was revised as requested.
2. Special Condition 16, the first paragraph was revised as requested
3. Special Condition 16, the third paragraph was not revised as requested. The change was unnecessary based on the current language.

The Agency has begun a program allowing the submittal of electronic Discharge Monitoring Reports (eDMRs) instead of paper Discharge Monitoring Reports (DMRs). If you are interested in eDMRs, more information can be found on the Agency website, http://epa.state.il.us/water/edmr/index.html. If your facility is not registered in the eDMR program, a supply of preprinted paper DMR Forms for your facility will be sent to you prior to the initiation of DMR reporting under the reissued permit. Additional information and instructions will accompany the preprinted DMRs upon their arrival.

The attached Permit is effective as of the date indicated on the first page of the Permit. Until the effective date of any re-issued Permit, the limitations and conditions of the previously-issued Permit remain in full effect. You have the right to appeal any condition of the Permit to the Illinois Pollution Control Board within a 35 day period following the issuance date.

4302 N. Main St., Rockford, IL 61103 (815)987-7760
595 S. State, Elgin, IL 60123 (847)608-3131
2125 S. First St., Champaign, IL 61820 (217)278-5800
2009 Mall St., Collinsville, IL 62234 (618)346-5120

9511 Harrison St., Des Plaines, IL 60016 (847)294-4000
5407 N. University St., Arbor 113, Peoria, IL 61614 (309)693-5462
2309 W. Main St., Suite 116, Marion, IL 62959 (618)993-7200
100 W. Randolph, Suite 11-300, Chicago, IL 60601 (312)814-6026

Should you have questions concerning the Permit, please contact Leslie Lowry at 217/782-0610.

Sincerely,

Alan Keller

Alan Keller, P.E.
Manager, Permit Section
Division of Water Pollution Control

SAK:DEL:LRL:12030801.daa

Attachment: Final Permit

cc: Records Unit
Compliance Assurance Section
Rockford Region
Billing
USEPA

NPDES Permit No. IL0048151

Illinois Environmental Protection Agency

Division of Water Pollution Control

1021 North Grand Avenue East

Springfield, Illinois 62794-9276

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

Reissued (NPDES) Permit

Expiration Date: July 31, 2018

Issue Date: July 5, 2013
Effective Date: August 1, 2013

Name and Address of Permittee:

Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, Illinois 60555

Facility Name and Address:

Exelon Generation Company, LLC
LaSalle County Generating Station
2601 N. 21st Street
Marseilles, Illinois 61341
(LaSalle County)

Discharge Number and Name:		Receiving Waters:
001	Cooling Pond Blowdown	Illinois River
A01	Demineralizer Regenerant Wastes	
B01	Sewage Treatment Plant Effluent	
C01	Wastewater Treatment System Effluent	
D01	Cooling Water Intake Screen Backwash	
E01	Unit 1 and 2 Radwaste Treatment System Effluent	
F01	Auxiliary Reactor Equipment Cooling and Flushing Water	
G01	North Site Stormwater Runoff	
H01	South Site Stormwater Runoff	
I01	Reverse Osmosis System Reject Water and Greensand Filter Backwash	
002	Illinois River Make-Up Water Intake Screen Backwash	Illinois River

In compliance with the provisions of the Illinois Environmental Protection Act, Title 35 of Ill. Adm. Code, Subtitle C and/or Subtitle D, Chapter 1, and the Clean Water Act (CWA), the above-named permittee is hereby authorized to discharge at the above location to the above-named receiving stream in accordance with the standard conditions and attachments herein.

Permittee is not authorized to discharge after the above expiration date. In order to receive authorization to discharge beyond the expiration date, the permittee shall submit the proper application as required by the Illinois Environmental Protection Agency (IEPA) not later than 180 days prior to the expiration date.

Alan Keller

Alan Keller, P.E.
Manager, Permit Section
Division of Water Pollution Control

SAK:LRL:12030801.daa

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NPDES Permit No. IL0048151

Effluent Limitations and Monitoring

1. From the effective date of this permit until the expiration date, the effluent of the following discharges shall be monitored and limited at all times as follows:

	LOAD LIMITS lbs/day DAF (DMF)		CONCENTRATION LIMITS mg/l			
PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall 001 – Cooling Pond Blowdown*
(Average Flow = 34.9 MGD)

This discharge consists of:

1. Main Condenser Cooling Water
2. Clean Condensate System Flushing and Maintenance (Alternate Route)
3. House Service Water
4. Demineralizer Regenerant Wastes (Outfall A01)
5. Sewage Treatment Plant Effluent (Outfall B01)
6. Wastewater Treatment System Effluent (Outfall C01)
7. Cooling Pond Intake Screen Backwash (Outfall D01)
8. Unit 1 and 2 Radwaste Treatment System Effluent (Outfall E01)
9. Auxiliary Reactor Equipment Cooling and Flushing Water (Outfall F01)
10. North Site Stormwater Runoff (Outfall G01)**
11. South Site Stormwater Runoff (Outfall H01)**
12. Reverse Osmosis System Reject Water and Greensand Filter Backwash (Outfall I01)
13. Water Softener Regenerant Waste
14. North Inlet Canal Stormwater Runoff**
15. South Inlet Canal Stormwater Runoff**
16. IDNR Fish Hatchery Effluents

PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE
Flow (MGD)	See Special Condition 1.				Daily	Continuous
pH	See Special Condition 2.				2/Month	Grab
Temperature	See Special Condition 3.				Daily	Continuous
Total Residual Chlorine / Total Residual Oxidant	See Special Condition 4 and 16.			0.05	2/Month	Grab
Zinc (Total)			Monitor Only		1/Quarter	Grab

* - See Special Condition 13

** - See Special Condition 8

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NPDES Permit No. IL0048151

Effluent Limitations and Monitoring

1. From the effective date of this permit until the expiration date, the effluent of the following discharges shall be monitored and limited at all times as follows:

PARAMETER	LOAD LIMITS lbs/day DAF (DMF) 30 DAY AVERAGE	LOAD LIMITS lbs/day DAF (DMF) DAILY MAXIMUM	CONCENTRATION LIMITS mg/l 30 DAY AVERAGE	CONCENTRATION LIMITS mg/l DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE
Outfall A01 – Demineralizer Regenerant Wastes* (Intermittent Discharge)						

This discharge consists of:

1. Make-Up Demineralizer Regenerant Wastes
2. Off-Specification Demineralized Water
3. Make-Up Demineralizer Maintenance Wastewater
4. Unit Waterbox Vacuum Pump Condensate
5. Radwaste Treatment Acid/Caustic System Drains

PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE
Flow (MGD)	See Special Condition 1.				1/Week	24 Hour Total
Total Suspended Solids			15	30	1/Week	Grab

* - Also discharge to the Wastewater Treatment System (Outfall C01) as an alternate route.

Outfall B01 – Sewage Treatment Plant Effluent
(DAF = 0.06 MGD)

This discharge consists of:

1. Sanitary Wastewater
2. Eyewash Station Wastewater

PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE
Flow (MGD)	See Special Condition 1.				Daily	Continuous
pH	See Special Condition 2.				2/Month	Grab
$CBOD_5$	13	42	25	50	2/Month	24 Hour Composite
Total Suspended Solids	15	50	30	60	2/Month	24 Hour Composite

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NPDES Permit No. IL0048151

Effluent Limitations and Monitoring

1. From the effective date of this permit until the expiration date, the effluent of the following discharges shall be monitored and limited at all times as follows:

PARAMETER	LOAD LIMITS lbs/day DAF (DMF) 30 DAY AVERAGE	LOAD LIMITS lbs/day DAF (DMF) DAILY MAXIMUM	CONCENTRATION LIMITS mg/l 30 DAY AVERAGE	CONCENTRATION LIMITS mg/l DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall C01 – Wastewater Treatment System Effluent
(DAF = 0.044 MGD)

This discharge consists of:

1. Turbine Building Fire and Miscellaneous Non-Radioactive Wastewater Sump
2. Greensand Filter Backwash (Alternative Route)
3. Diesel Fuel Storage and Service Water Building Sump
4. Auxiliary Boiler Blowdown
5. Water Softener Regenerant Waste
6. Demineralizer Regenerant Wastes (Outfall A01 Alternate Route)
7. Heat Bay Building Roof Area
8. Fire Protection System Flushing and Maintenance*
9. Service Water System Flushing and Maintenance*
10. Domestic Water System Flushing and Maintenance*
11. Clean Condensate System Flushing and Maintenance**
12. Laboratory Liquid Wastes
13. Station Heat System Condensate
14. Diesel Generator Cooling Water
15. Standby Liquid Control Test Skid Flush Water
16. Groundwater

PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE
Flow (MGD)	See Special Condition 1				Daily	Continuous
pH	See Special Condition 2				1/Week	Grab
Total Suspended Solids	5	17	15	30	1/Month	24 Hour Composite
Oil & Grease	2.5	3.34	15	20	1/Month	Grab

* - Also discharges to the North Site Stormwater Runoff (Outfall G01) and/or South Site Stormwater Runoff (Outfall H01) as an alternate route.
** - Also discharges to the Cooling Pond Blowdown (Outfall 001) via the service water system and resulting main condenser cooling water as an alternate route.

Outfall D01 – Cooling Water Intake Screen Backwash*
(Intermittent Discharge)

* - This discharge is limited to cooling water intake screen backwash free from other wastewater discharges. Adequate maintenance of the trash basket is required to prevent the discharge of floating debris collected on intake screens back to the cooling pond.

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NPDES Permit No. IL0048151

Effluent Limitations and Monitoring

1. From the effective date of this permit until the expiration date, the effluent of the following discharges shall be monitored and limited at all times as follows:

	LOAD LIMITS lbs/day DAF (DMF)		CONCENTRATION LIMITS mg/l			
PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall E01 – Unit 1 and 2 Radwaste Treatment System Effluent
(Intermittent Discharge)

This discharge consists of:

1. Equipment Drains in the Turbine, Auxiliary, and Reactor Buildings
2. Floor Drains in the Turbine, Auxiliary, and Reactor Buildings
3. Condensate Polisher Waste from the Turbine Building
4. Decontamination and Laundry Waste

PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE
Flow (MGD)	See Special Condition 1.				1/Week	Estimate
Total Suspended Solids			15	30	1/Week	Grab
Oil & Grease			15	20	1/Week	Grab

Outfall F01 – Auxiliary Reactor Equipment Cooling and Flushing Water*
(Intermittent Discharge)

* - This discharge is limited to auxiliary reactor equipment cooling and flushing water free from other wastewater discharges.

Outfall G01 – North Site Stormwater Runoff*
(Intermittent Discharge)

This discharge consists of:

1. Fire Protection System Flushing and Maintenance (Alternate Route)
2. Service Water System Flushing and Maintenance (Alternate Route)
3. Domestic Water System Flushing and Maintenance (Alternate Route)
4. Clean Condensate System Flushing and Maintenance (Alternate Route)
5. North Site Uncontaminated Stormwater Runoff

* - See Special Condition 8.

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NPDES Permit No. IL0048151

Effluent Limitations and Monitoring

1. From the effective date of this permit until the expiration date, the effluent of the following discharges shall be monitored and limited at all times as follows:

PARAMETER	LOAD LIMITS lbs/day DAF (DMF) 30 DAY AVERAGE	DAILY MAXIMUM	CONCENTRATION LIMITS mg/l 30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall H01 – South Site Stormwater Runoff*
(Intermittent Discharge)

This discharge consists of:

1. Fire Protection System Flushing and Maintenance (Alternate Route)
2. Service Water System Flushing and Maintenance (Alternate Route)
3. Domestic Water System Flushing and Maintenance (Alternate Route)
4. Clean Condensate System Flushing and Maintenance (Alternate Route)
5. South Site Uncontaminated Stormwater Runoff

* - See Special Condition 8.

Outfall I01 – Reverse Osmosis System Reject Water and Greensand Filter Backwash
(Average Flow = 0.003 MGD)

PARAMETER	30 DAY AVERAGE (lbs/day)	DAILY MAXIMUM (lbs/day)	30 DAY AVERAGE (mg/l)	DAILY MAXIMUM (mg/l)	SAMPLE FREQUENCY	SAMPLE TYPE
Flow (MGD)	See Special Condition 1.				1/Week	24 Hour Total
Total Suspended Solids			15	30	1/Month	Grab

Outfall 002 – Illinois River Makeup Water Intake Screen Backwash*
(Intermittent Discharge)

This discharge consists of:

1. River Intake Screen Backwash
2. Trench Wash Water
3. Process Sampling Discharge
4. Lake Make-Up Pump Gland Leakoff, Coolers, Reliefs, and Min Flow
5. Lake Make-Up Pump Strainer Backwash
6. Air Compressor Receiver and Prefilter Drainage
7. Dewatering Pump Discharge
8. Fire Protection Water
9. River Screen House Switchyard Stormwater Runoff**
10. River Screen House Floor Drains and Roof Drains

* - Adequate maintenance of the intake screen system is required to prevent the discharge of floating debris collected on intake screens back to the Illinois River.
** - See Special Condition 8.

NPDES Permit No. IL0048151

Special Conditions

SPECIAL CONDITION 1. Flow shall be measured in units of Million Gallons per Day (MGD) and reported as a monthly average and a daily maximum on the Discharge Monitoring Report.

SPECIAL CONDITION 2. The pH shall be in the range 6.0 to 9.0. The monthly minimum and monthly maximum values shall be reported on the DMR form.

SPECIAL CONDITION 3. This facility meets the criteria for establishment of a formal mixing zone for thermal discharges pursuant to 35 IAC 302.102. The following mixing zone defines the area and volume of the receiving water body in which mixing is allowed to occur. Water quality standards for temperature listed in table below must be met at every point outside of the mixing zone.

	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
°F	60	60	60	90	90	90	90	90	90	90	90	60
°C	16	16	16	32	32	32	32	32	32	32	32	16

A. The temperature at the edge of the mixing zone should be calculated using the mass balance equation below:

$T_{EDGE} = [0.25 \times (Q_{US} \times T_{US}) + Q_E \times T_E] / (0.25 \times Q_{US} + Q_E)$

Where:

T_{EDGE} = Temperature at the edge of the mixing zone.
Q_{US} = Upstream Flow
T_{US} = Upstream Temperature
Q_E = Effluent Flow
T_E = Temperature of the effluent.

B. There shall be no abnormal temperature changes that may adversely affect aquatic life unless caused by natural conditions. The normal daily and seasonal temperature fluctuations which existed before the addition of heat due to other than natural causes shall be maintained.

C. The maximum temperature rise above natural temperatures shall not exceed 2.8° C (5° F).

D. The water temperature at the edge of the mixing zone defined above shall not exceed the maximum limits in the foregoing table during more than one percent of the hours in the 12 month period ending with any month. Moreover, at no time shall the water temperature at the edge of the mixing zone exceed the maximum limits in the foregoing table by more than 1.7° C (3° F).

E. The monthly maximum value shall be reported on the DMR form.

SPECIAL CONDITION 4. All samples for Total Residual Chlorine / Total Residual Oxidant shall be analyzed by an applicable method contained in 40 CFR 136, equivalent in accuracy to low-level amperometric titration. Any analytical variability of the method used shall be considered when determining the accuracy and precision of the results obtained.

SPECIAL CONDITION 5. There shall be no discharge of complexed metal bearing wastestreams and associated rinses from chemical metal cleaning unless this permit has been modified to include the new discharge.

SPECIAL CONDITION 6. The Permittee shall record monitoring results on Discharge Monitoring Report (DMR) Forms using one such form for each outfall each month.

In the event that an outfall does not discharge during a monthly reporting period, the DMR Form shall be submitted with no discharge indicated.

The Permittee may choose to submit electronic DMRs (eDMRs) instead of mailing paper DMRs to the IEPA. More information, including registration information for the eDMR program, can be obtained on the IEPA website, http://www.epa.state.il.us/water/edmr/index.html

The completed Discharge Monitoring Report forms shall be submitted to IEPA no later than the 28th day of the following month, unless otherwise specified by the permitting authority.

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NPDES Permit No. IL0048151

Special Conditions

Permittees not using eDMRs shall mail Discharge Monitoring Reports with an original signature to the IEPA at the following address:

Illinois Environmental Protection Agency
Division of Water Pollution Control
1021 North Grand Avenue East
Post Office Box 19276
Springfield, Illinois 62794-9276

Attention: Compliance Assurance Section, Mail Code # 19

SPECIAL CONDITION 7. The upset defense provisions as defined in 40 CFR 122.41(n) are hereby incorporated by reference.

SPECIAL CONDITION 8.

STORM WATER POLLUTION PREVENTION PLAN (SWPPP)

A. A storm water pollution prevention plan shall be maintained by the permittee for the storm water associated with industrial activity at this facility. The plan shall identify potential sources of pollution which may be expected to affect the quality of storm water discharges associated with the industrial activity at the facility. In addition, the plan shall describe and ensure the implementation of practices which are to be used to reduce the pollutants in storm water discharges associated with industrial activity at the facility and to assure compliance with the terms and conditions of this permit. The permittee shall modify the plan if substantive changes are made or occur affecting compliance with this condition.

1. Waters not classified as impaired pursuant to Section 303(d) of the Clean Water Act.

   Unless otherwise specified by federal regulation, the storm water pollution prevention plan shall be designed for a storm event equal to or greater than a 25-year 24-hour rainfall event.

2. Waters classified as impaired pursuant to Section 303(d) of the Clean Water Act.

   For any site which discharges directly to an impaired water identified in the Agency's 303(d) listing, and if any parameter in the subject discharge has been identified as the cause of impairment, the storm water pollution prevention plan shall be designed for a storm event equal to or greater than a 25-year 24-hour rainfall event. If required by federal regulations, the storm water pollution prevention plan shall adhere to a more restrictive design criteria.

B. The operator or owner of the facility shall make a copy of the plan available to the Agency at any reasonable time upon request.

   Facilities which discharge to a municipal separate storm sewer system shall also make a copy available to the operator of the municipal system at any reasonable time upon request.

C. The permittee may be notified by the Agency at any time that the plan does not meet the requirements of this condition. After such notification, the permittee shall make changes to the plan and shall submit a written certification that the requested changes have been made. Unless otherwise provided, the permittee shall have 30 days after such notification to make the changes.

D. The discharger shall amend the plan whenever there is a change in construction, operation, or maintenance which may affect the discharge of significant quantities of pollutants to the waters of the State or if a facility inspection required by paragraph H of this condition indicates that an amendment is needed. The plan should also be amended if the discharger is in violation of any conditions of this permit, or has not achieved the general objective of controlling pollutants in storm water discharges. Amendments to the plan shall be made within 30 days of any proposed construction or operational changes at the facility, and shall be provided to the Agency for review upon request.

E. The plan shall provide a description of potential sources which may be expected to add significant quantities of pollutants to storm water discharges, or which may result in non-storm water discharges from storm water outfalls at the facility. The plan shall include, at a minimum, the following items:

1. A topographic map extending one-quarter mile beyond the property boundaries of the facility, showing: the facility, surface water bodies, wells (including injection wells), seepage pits, infiltration ponds, and the discharge points where the facility's storm water discharges to a municipal storm drain system or other water body. The requirements of this paragraph may be included on the site map if appropriate. Any map or portion of map may be withheld for security reasons.

2. A site map showing:

   i. The storm water conveyance and discharge structures;

NPDES Permit No. IL0048151

Special Conditions

ii. An outline of the storm water drainage areas for each storm water discharge point;

iii. Paved areas and buildings;

iv. Areas used for outdoor manufacturing, storage, or disposal of significant materials, including activities that generate significant quantities of dust or particulates.

v. Location of existing storm water structural control measures (dikes, coverings, detention facilities, etc.);

vi. Surface water locations and/or municipal storm drain locations

vii. Areas of existing and potential soil erosion;

viii. Vehicle service areas;

ix. Material loading, unloading, and access areas.

x. Areas under items iv and ix above may be withheld from the site for security reasons.

3. A narrative description of the following:

i. The nature of the industrial activities conducted at the site, including a description of significant materials that are treated, stored or disposed of in a manner to allow exposure to storm water;

ii. Materials, equipment, and vehicle management practices employed to minimize contact of significant materials with storm water discharges;

iii. Existing structural and non-structural control measures to reduce pollutants in storm water discharges;

iv. Industrial storm water discharge treatment facilities;

v. Methods of onsite storage and disposal of significant materials.

4. A list of the types of pollutants that have a reasonable potential to be present in storm water discharges in significant quantities. Also provide a list of any pollutant that is listed as impaired in the most recent 303(d) report

5. An estimate of the size of the facility in acres or square feet, and the percent of the facility that has impervious areas such as pavement or buildings.

6. A summary of existing sampling data describing pollutants in storm water discharges.

F. The plan shall describe the storm water management controls which will be implemented by the facility. The appropriate controls shall reflect identified existing and potential sources of pollutants at the facility. The description of the storm water management controls shall include:

1. Storm Water Pollution Prevention Personnel - Identification by job titles of the individuals who are responsible for developing, implementing, and revising the plan.

2. Preventive Maintenance - Procedures for inspection and maintenance of storm water conveyance system devices such as oil/water separators, catch basins, etc., and inspection and testing of plant equipment and systems that could fail and result in discharges of pollutants to storm water.

3. Good Housekeeping - Good housekeeping requires the maintenance of clean, orderly facility areas that discharge storm water. Material handling areas shall be inspected and cleaned to reduce the potential for pollutants to enter the storm water conveyance system.

4. Spill Prevention and Response - Identification of areas where significant materials can spill into or otherwise enter the storm water conveyance systems and their accompanying drainage points. Specific material handling procedures, storage requirements, spill cleanup equipment and procedures should be identified, as appropriate. Internal notification procedures for spills of significant materials should be established.

5. Storm Water Management Practices - Storm water management practices are practices other than those which control the source of pollutants. They include measures such as installing oil and grit separators, diverting storm water into retention

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basins, etc. Based on assessment of the potential of various sources to contribute pollutants, measures to remove pollutants from storm water discharge shall be implemented. In developing the plan, the following management practices shall be considered:

i. Containment - Storage within berms or other secondary containment devices to prevent leaks and spills from entering storm water runoff. To the maximum extent practicable storm water discharged from any area where material handling equipment or activities, raw material, intermediate products, final products, waste materials, by-products, or industrial machinery are exposed to storm water should not enter vegetated areas or surface waters or infiltrate into the soil unless adequate treatment is provided.

ii. Oil & Grease Separation - Oil/water separators, booms, skimmers or other methods to minimize oil contaminated storm water discharges.

iii. Debris & Sediment Control - Screens, booms, sediment ponds or other methods to reduce debris and sediment in storm water discharges.

iv. Waste Chemical Disposal - Waste chemicals such as antifreeze, degreasers and used oils shall be recycled or disposed of in an approved manner and in a way which prevents them from entering storm water discharges.

v. Storm Water Diversion - Storm water diversion away from materials manufacturing, storage and other areas of potential storm water contamination. Minimize the quantity of storm water entering areas where material handling equipment of activities, raw material, intermediate products, final products, waste materials, by-products, or industrial machinery are exposed to storm water using green infrastructure techniques where practicable in the areas outside the exposure area, and otherwise divert storm water away from exposure area.

vi. Covered Storage or Manufacturing Areas - Covered fueling operations, materials manufacturing and storage areas to prevent contact with storm water.

vii. Storm Water Reduction - Install vegetation on roofs of buildings within adjacent to the exposure area to detain and evapotranspirate runoff where precipitation falling on the roof is not exposed to contaminants, to minimize storm water runoff; capture storm water in devices that minimize the amount of storm water runoff and use this water as appropriate based on quality.

6. Sediment and Erosion Prevention - The plan shall identify areas which due to topography, activities, or other factors, have a high potential for significant soil erosion. The plan shall describe measures to limit erosion.

7. Employee Training - Employee training programs shall inform personnel at all levels of responsibility of the components and goals of the storm water pollution control plan. Training should address topics such as spill response, good housekeeping and material management practices. The plan shall identify periodic dates for such training.

8. Inspection Procedures - Qualified plant personnel shall be identified to inspect designated equipment and plant areas. A tracking or follow-up procedure shall be used to ensure appropriate response has been taken in response to an inspection. Inspections and maintenance activities shall be documented and recorded.

G. Non-Storm Water Discharge - The plan shall include a certification that the discharge has been tested or evaluated for the presence of non-storm water discharge. The certification shall include a description of any test for the presence of non-storm water discharges, the methods used, the dates of the testing, and any onsite drainage points that were observed during the testing. Any facility that is unable to provide this certification must describe the procedure of any test conducted for the presence of non-storm water discharges, the test results, potential sources of non-storm water discharges to the storm sewer, and why adequate tests for such storm sewers were not feasible.

H. Quarterly Visual Observation of Discharges - The requirements and procedures for quarterly visual observations are applicable to all outfalls covered by this condition.

1. You must perform and document a quarterly visual observation of a storm water discharge associated with industrial activity from each outfall. The visual observation must be made during daylight hours. If no storm event resulted in runoff during daylight hours from the facility during a monitoring quarter, you are excused from the visual observations requirement for that quarter, provided you document in your records that no runoff occurred. You must sign and certify the document.

2. Your visual observation must be made on samples collected as soon as practical, but not to exceed 1 hour or when the runoff or snow melt begins discharging from your facility. All samples must be collected from a storm event discharge that is greater than 0.1 inch in magnitude and that occurs at least 72 hours from the previously measureable (greater than 0.1 inch rainfall) storm event. The observation must document: color, odor, clarity, floating solids, settled solids, suspended solids, foam, oil

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sheen, and other obvious indicators of storm water pollution. If visual observations indicate any unnatural color, odor, turbidity, floatable material, oil sheen or other indicators of storm water pollution, the permittee shall obtain a sample and monitor for the parameter or the list of pollutants in Part E.4.

3. You must maintain your visual observation reports onsite with the SWPPP. The report must include the observation date and time, inspection personnel, nature of the discharge (i.e., runoff or snow melt), visual quality of the storm water discharge (including observations of color, odor, floating solids, settled solids, suspended solids, foam, oil sheen, and other obvious indicators of storm water pollution), and probable sources of any observed storm water contamination.

4. You may exercise a waiver of the visual observation requirement at a facility that is inactive or unstaffed, as long as there are no industrial materials or activities exposed to storm water. If you exercise this waiver, you must maintain a certification with your SWPPP stating that the site is inactive and unstaffed, and that there are no industrial materials or activities exposed to storm water.

5. Representative Outfalls - If your facility has two or more outfalls that you believe discharge substantially identical effluents, based on similarities of the industrial activities, significant materials, size of drainage areas, and storm water management practices occurring within the drainage areas of the outfalls, you may conduct visual observations of the discharge at just one of the outfalls and report that the results also apply to the substantially identical outfall(s).

6. The visual observation documentation shall be made available to the Agency and general public upon written request.

I. The permittee shall conduct an annual facility inspection to verify that all elements of the plan, including the site map, potential pollutant sources, and structural and non-structural controls to reduce pollutants in industrial storm water discharges are accurate. Observations that require a response and the appropriate response to the observation shall be retained as part of the plan. Records documenting significant observations made during the site inspection shall be submitted to the Agency in accordance with the reporting requirements of this permit.

J. This plan should briefly describe the appropriate elements of other program requirements, including Spill Prevention Control and Countermeasures (SPCC) plans required under Section 311 of the CWA and the regulations promulgated there under, and Best Management Programs under 40 CFR 125.100.

K. The plan is considered a report that shall be available to the public at any reasonable time upon request.

L. The plan shall include the signature and title of the person responsible for preparation of the plan and include the date of initial preparation and each amendment thereto.

M. Facilities which discharge storm water associated with industrial activity to municipal separate storm sewers may also be subject to additional requirement imposed by the operator of the municipal system

Construction Authorization

Authorization is hereby granted to construct treatment works and related equipment that may be required by the Storm Water Pollution Prevention Plan developed pursuant to this permit.

This Authorization is issued subject to the following condition(s).

N. If any statement or representation is found to be incorrect, this authorization may be revoked and the permittee there upon waives all rights there under.

O. The issuance of this authorization (a) does not release the permittee from any liability for damage to persons or property caused by or resulting from the installation, maintenance or operation of the proposed facilities; (b) does not take into consideration the structural stability of any units or part of this project; and (c) does not release the permittee from compliance with other applicable statutes of the State of Illinois, or other applicable local law, regulations or ordinances.

P. Plans and specifications of all treatment equipment being included as part of the stormwater management practice shall be included in the SWPPP.

Q. Construction activities which result from treatment equipment installation, including clearing, grading and excavation activities which result in the disturbance of one acre or more of land area, are not covered by this authorization. The permittee shall contact the IEPA regarding the required permit(s).

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R. The facility shall submit an electronic copy of the annual inspection report to the Illinois Environmental Protection Agency. The report shall include results of the annual facility inspection which is required by Part I of this condition. The report shall also include documentation of any event (spill, treatment unit malfunction, etc.) which would require an inspection, results of the inspection, and any subsequent corrective maintenance activity. The report shall be completed and signed by the authorized facility employee(s) who conducted the inspection(s). The annual inspection report is considered a public document that shall be available at any reasonable time upon request.

S. The first report shall contain information gathered during the one year time period beginning with the effective date of coverage under this permit and shall be submitted no later than 60 days after this one year period has expired. Each subsequent report shall contain the previous year's information and shall be submitted no later than one year after the previous year's report was due.

T. If the facility performs inspections more frequently than required by this permit, the results shall be included as additional information in the annual report.

U. The permittee shall retain the annual inspection report on file at least 3 years. This period may be extended by request of the Illinois Environmental Protection Agency at any time.

Annual inspection reports shall be mailed to the following address:

Illinois Environmental Protection Agency
Bureau of Water
Compliance Assurance Section
Annual Inspection Report
1021 North Grand Avenue East
Post Office Box 19276
Springfield, Illinois 62794-9276

V. The permittee shall notify any regulated small municipal separate storm sewer owner (MS4 Community) that they maintain coverage under an individual NPDES permit. The permittee shall submit any SWPPP or any annual inspection to the MS4 community upon request by the MS4 community.

SPECIAL CONDITION 9. This permit authorizes the use of water treatment additives that were requested as part of this renewal. The use of any new additives, or change in those previously approved by the Agency, or if the permittee increases the feed rate or quantity of the additives used beyond what has been approved by the Agency, the permittee shall request a modification of this permit in accordance with the Standard Conditions - Attachment H.

The permittee shall submit to the Agency on a yearly basis a report summarizing their efforts with water treatment suppliers to find a suitable alternative to phosphorus based additives.

SPECIAL CONDITION 10. This permit may be modified to include different final effluent limitations or requirements which are consistent with applicable laws, regulations, or judicial orders. The Agency will public notice the permit modification.

SPECIAL CONDITION 11. The effluent, alone or in combination with other sources, shall not cause a violation of any applicable water quality standard outlined in 35 Ill. Adm. Code 302.

SPECIAL CONDITION 12. The use or operation of this facility shall be by or under the supervision of a Certified Class K operator.

SPECIAL CONDITION 13. There shall be no discharge of polychlorinated biphenyl compounds (PCBs).

SPECIAL CONDITION 14. Samples taken in compliance with the effluent monitoring requirements shall be taken at a point representative of the discharge, but prior to entry into the receiving stream.

SPECIAL CONDITION 15. The facility utilizes a closed-cycle recirculating cooling system, a 2058 acre cooling pond, for cooling of plant condensers and is determined to be the equivalent of Best Technology Available (BTA) for cooling water intake structures to prevent/minimize impingement mortality in accordance with the Best Professional Judgment (BPJ) provisions of 40 CFR 125.3 because it allows the facility to only withdraw the amount of water necessary to maintain the cooling pond level rather than the entire volume used for cooling of the plant condensers.

In order for the Agency to evaluate the potential impacts of cooling water intake structure operations pursuant to 40 CFR 125.90(b), the permittee shall prepare and submit information to the Agency outlining current intake structure conditions at this facility, including a detailed description of the current intake structure operation and design, description of any operational or structural modifications from

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original design parameters, source waterbody flow information as necessary.

The information shall also include a summary of historical 316(b) related intake impingement and/or entrainment studies, if any, as well as current impingement mortality and/or entrainment characterization data; and shall be submitted to the Agency within six (6) months of the permit's effective date.

Upon the receipt and review of this information, the permit may be modified to require the submittal of additional information based on a Best Professional Judgment review by the Agency. This permit may also be revised or modified in accordance with any laws, regulations, or judicial orders pursuant to Section 316(b) of the Clean Water Act.

SPECIAL CONDITION 16. For a period of 18 months following the effective date of this permit during times when the condenser cooling water is chlorinated intermittently, Total Residual Chlorine may be discharged from each generating unit's main condensers for no more than 2 hours per day. During such authorized discharge time period, the maximum discharge limit is 0.2 mg/l, measured as an instantaneous maximum.

A Total Residual Chlorine limit of 0.05 mg/l (Daily Maximum) for outfall 001 shall become effective 18 months from the effective date of this Permit.

The Permittee shall construct a dechlorination system or some alternative means of compliance in accordance with the following schedule:

1. Status Report	4 months from the effective date
2. Commence Construction	10 months from the effective date
3. Status Report	14 months from the effective date
4. Complete Construction	16 months from the effective date
5. Obtain Operation Level	18 months from the effective date

Compliance dates set out in this Permit may be superseded or supplemented by compliance dates in judicial orders, or Pollution Control Board orders. This Permit may be modified, with Public Notice, to include such revised compliance dates.

The Permittee shall operate the dechlorination system or an alternative means of compliance in a manner to ensure continuous compliance with the Total Residual Chlorine limit, not to the extent that will result in violations of other permitted effluent characteristic, or water quality standards.

REPORTING

The Permittee shall submit a report no later than fourteen (14) days following the completion dates indicated above for each numbered item in the compliance schedule, indicating, a) the date the item was completed, or b) that the item was not completed, the reason for non-completion, and the anticipated completion date.

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Attachment H

Standard Conditions

Definitions

Act means the Illinois Environmental Protection Act, 415 ILCS 5 as Amended.

Agency means the Illinois Environmental Protection Agency.

Board means the Illinois Pollution Control Board.

Clean Water Act (formerly referred to as the Federal Water Pollution Control Act) means Pub. L 92-500, as amended. 33 U.S.C. 1251 et seq.

NPDES (National Pollutant Discharge Elimination System) means the national program for issuing, modifying, revoking and reissuing, terminating, monitoring and enforcing permits, and imposing and enforcing pretreatment requirements, under Sections 307, 402, 318 and 405 of the Clean Water Act.

USEPA means the United States Environmental Protection Agency.

Daily Discharge means the discharge of a pollutant measured during a calendar day or any 24-hour period that reasonably represents the calendar day for purposes of sampling. For pollutants with limitations expressed in units of mass, the "daily discharge" is calculated as the total mass of the pollutant discharged over the day. For pollutants with limitations expressed in other units of measurements, the "daily discharge" is calculated as the average measurement of the pollutant over the day.

Maximum Daily Discharge Limitation (daily maximum) means the highest allowable daily discharge.

Average Monthly Discharge Limitation (30 day average) means the highest allowable average of daily discharges over a calendar month, calculated as the sum of all daily discharges measured during a calendar month divided by the number of daily discharges measured during that month.

Average Weekly Discharge Limitation (7 day average) means the highest allowable average of daily discharges over a calendar week, calculated as the sum of all daily discharges measured during a calendar week divided by the number of daily discharges measured during that week.

Best Management Practices (BMPs) means schedules of activities, prohibitions of practices, maintenance procedures, and other management practices to prevent or reduce the pollution of waters of the State. BMPs also include treatment requirements, operating procedures, and practices to control plant site runoff, spillage or leaks, sludge or waste disposal, or drainage from raw material storage.

Aliquot means a sample of specified volume used to make up a total composite sample.

Grab Sample means an individual sample of at least 100 milliliters collected at a randomly-selected time over a period not exceeding 15 minutes.

24-Hour Composite Sample means a combination of at least 8 sample aliquots of at least 100 milliliters, collected at periodic intervals during the operating hours of a facility over a 24-hour period.

8-Hour Composite Sample means a combination of at least 3 sample aliquots of at least 100 milliliters, collected at periodic intervals during the operating hours of a facility over an 8-hour period.

Flow Proportional Composite Sample means a combination of sample aliquots of at least 100 milliliters collected at periodic intervals such that either the time interval between each aliquot or the volume of each aliquot is proportional to either the stream flow at the time of sampling or the total stream flow since the collection of the previous aliquot.

(1) **Duty to comply.** The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Act and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application. The permittee shall comply with effluent standards or prohibitions established under Section 307(a) of the Clean Water Act for toxic pollutants within the time provided in the regulations that establish these standards or prohibitions, even if the permit has not yet been modified to incorporate the requirements.

(2) **Duty to reapply.** If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must apply for and obtain a new permit. If the permittee submits a proper application as required by the Agency no later than 180 days prior to the expiration date, this permit shall continue in full force and effect until the final Agency decision on the application has been made.

(3) **Need to halt or reduce activity not a defense.** It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit

(4) **Duty to mitigate.** The permittee shall take all reasonable steps to minimize or prevent any discharge in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment.

(5) **Proper operation and maintenance.** The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up, or auxiliary facilities, or similar systems only when necessary to achieve compliance with the conditions of the permit.

(6) **Permit actions.** This permit may be modified, revoked and reissued, or terminated for cause by the Agency pursuant to 40 CFR 122.62 and 40 CFR 122.63. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

(7) **Property rights.** This permit does not convey any property rights of any sort, or any exclusive privilege.

(8) **Duty to provide information.** The permittee shall furnish to the Agency within a reasonable time, any information which the Agency may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also furnish to the Agency upon request, copies of records required to be kept by this permit.

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(9) **Inspection and entry.** The permittee shall allow an authorized representative of the Agency or USEPA (including an authorized contractor acting as a representative of the Agency or USEPA), upon the presentation of credentials and other documents as may be required by law, to:
   (a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;
   (b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;
   (c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and
   (d) Sample or monitor at reasonable times, for the purpose of assuring permit compliance, or as otherwise authorized by the Act, any substances or parameters at any location.

(10) **Monitoring and records.**
   (a) Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.
   (b) The permittee shall retain records of all monitoring information, including all calibration and maintenance records, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least 3 years from the date of this permit, measurement, report or application. Records related to the permittee's sewage sludge use and disposal activities shall be retained for a period of at least five years (or longer as required by 40 CFR Part 503). This period may be extended by request of the Agency or USEPA at any time.
   (c) Records of monitoring information shall include:
      (1) The date, exact place, and time of sampling or measurements;
      (2) The individual(s) who performed the sampling or measurements;
      (3) The date(s) analyses were performed;
      (4) The individual(s) who performed the analyses;
      (5) The analytical techniques or methods used; and
      (6) The results of such analyses.
   (d) Monitoring must be conducted according to test procedures approved under 40 CFR Part 136, unless other test procedures have been specified in this permit. Where no test procedure under 40 CFR Part 136 has been approved, the permittee must submit to the Agency a test method for approval. The permittee shall calibrate and perform maintenance procedures on all monitoring and analytical instrumentation at intervals to ensure accuracy of measurements.

(11) **Signatory requirement.** All applications, reports or information submitted to the Agency shall be signed and certified.
   (a) **Application.** All permit applications shall be signed as follows:
      (1) For a corporation: by a principal executive officer of at least the level of vice president or a person or position having overall responsibility for environmental matters for the corporation:
      (2) For a partnership or sole proprietorship: by a general partner or the proprietor, respectively; or
      (3) For a municipality, State, Federal, or other public agency: by either a principal executive officer or ranking elected official.
   (b) **Reports.** All reports required by permits, or other information requested by the Agency shall be signed by a person described in paragraph (a) or by a duly authorized representative of that person. A person is a duly authorized representative only if:
      (1) The authorization is made in writing by a person described in paragraph (a); and
      (2) The authorization specifies either an individual or a position responsible for the overall operation of the facility, from which the discharge originates, such as a plant manager, superintendent or person of equivalent responsibility; and
      (3) The written authorization is submitted to the Agency.
   (c) **Changes of Authorization.** If an authorization under (b) is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of (b) must be submitted to the Agency prior to or together with any reports, information, or applications to be signed by an authorized representative.
   (d) **Certification.** Any person signing a document under paragraph (a) or (b) of this section shall make the following certification:

   I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

(12) **Reporting requirements.**
   (a) **Planned changes.** The permittee shall give notice to the Agency as soon as possible of any planned physical alterations or additions to the permitted facility.
   Notice is required when:
      (1) The alteration or addition to a permitted facility may meet one of the criteria for determining whether a facility is a new source pursuant to 40 CFR 122.29 (b); or
      (2) The alteration or addition could significantly change the nature or increase the quantity of pollutants discharged. This notification applies to pollutants which are subject neither to effluent limitations in the permit, nor to notification requirements pursuant to 40 CFR 122.42 (a)(1).
      (3) The alteration or addition results in a significant change in the permittee's sludge use or disposal practices, and such alteration, addition, or change may justify the application of permit conditions that are different from or absent in the existing permit, including notification of additional use or disposal sites not reported during the permit application process or not reported pursuant to an approved land application plan.
   (b) **Anticipated noncompliance.** The permittee shall give advance notice to the Agency of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.
   (c) **Transfers.** This permit is not transferable to any person except after notice to the Agency.
   (d) **Compliance schedules.** Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 14 days following each schedule date.
   (e) **Monitoring reports.** Monitoring results shall be reported at the intervals specified elsewhere in this permit.
      (1) Monitoring results must be reported on a Discharge Monitoring Report (DMR).

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(2) If the permittee monitors any pollutant more frequently than required by the permit, using test procedures approved under 40 CFR 136 or as specified in the permit, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

(3) Calculations for all limitations which require averaging of measurements shall utilize an arithmetic mean unless otherwise specified by the Agency in the permit.

(f) **Twenty-four hour reporting.** The permittee shall report any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24-hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within 5 days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and time; and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The following shall be included as information which must be reported within 24-hours:

(1) Any unanticipated bypass which exceeds any effluent limitation in the permit.

(2) Any upset which exceeds any effluent limitation in the permit.

(3) Violation of a maximum daily discharge limitation for any of the pollutants listed by the Agency in the permit or any pollutant which may endanger health or the environment.

The Agency may waive the written report on a case-by-case basis if the oral report has been received within 24-hours.

(g) **Other noncompliance.** The permittee shall report all instances of noncompliance not reported under paragraphs (12) (d), (e), or (f), at the time monitoring reports are submitted. The reports shall contain the information listed in paragraph (12) (f).

(h) **Other information.** Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application, or in any report to the Agency, it shall promptly submit such facts or information.

(13) **Bypass.**

(a) Definitions.

(1) Bypass means the intentional diversion of waste streams from any portion of a treatment facility.

(2) Severe property damage means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

(b) Bypass not exceeding limitations. The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it also is for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of paragraphs (13)(c) and (13)(d).

(c) Notice.

(1) Anticipated bypass. If the permittee knows in advance of the need for a bypass, it shall submit prior notice, if possible at least ten days before the date of the bypass.

(2) Unanticipated bypass. The permittee shall submit notice of an unanticipated bypass as required in paragraph (12)(f) (24-hour notice).

(d) Prohibition of bypass.

(1) Bypass is prohibited, and the Agency may take enforcement action against a permittee for bypass, unless:

(i) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(ii) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and

(iii) The permittee submitted notices as required under paragraph (13)(c).

(2) The Agency may approve an anticipated bypass, after considering its adverse effects, if the Agency determines that it will meet the three conditions listed above in paragraph (13)(d)(1).

(14) **Upset.**

(a) Definition. Upset means an exceptional incident in which there is unintentional and temporary noncompliance with technology based permit effluent limitations because of factors beyond the reasonable control of the permittee. An upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation.

(b) Effect of an upset. An upset constitutes an affirmative defense to an action brought for noncompliance with such technology based permit effluent limitations if the requirements of paragraph (14)(c) are met. No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

(c) Conditions necessary for a demonstration of upset. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs, or other relevant evidence that:

(1) An upset occurred and that the permittee can identify the cause(s) of the upset;

(2) The permitted facility was at the time being properly operated; and

(3) The permittee submitted notice of the upset as required in paragraph (12)(f)(2) (24-hour notice).

(4) The permittee complied with any remedial measures required under paragraph (4).

(d) Burden of proof. In any enforcement proceeding the permittee seeking to establish the occurrence of an upset has the burden of proof.

(15) **Transfer of permits.** Permits may be transferred by modification or automatic transfer as described below:

(a) Transfers by modification. Except as provided in paragraph (b), a permit may be transferred by the permittee to a new owner or operator only if the permit has been modified or revoked and reissued pursuant to 40 CFR 122.62 (b) (2), or a minor modification made pursuant to 40 CFR 122.63 (d), to identify the new permittee and incorporate such other requirements as may be necessary under the Clean Water Act.

(b) Automatic transfers. As an alternative to transfers under paragraph (a), any NPDES permit may be automatically

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transferred to a new permittee if:
(1) The current permittee notifies the Agency at least 30 days in advance of the proposed transfer date;
(2) The notice includes a written agreement between the existing and new permittees containing a specified date for transfer of permit responsibility, coverage and liability between the existing and new permittees; and
(3) The Agency does not notify the existing permittee and the proposed new permittee of its intent to modify or revoke and reissue the permit. If this notice is not received, the transfer is effective on the date specified in the agreement.

(16) All manufacturing, commercial, mining, and silvicultural dischargers must notify the Agency as soon as they know or have reason to believe:
(a) That any activity has occurred or will occur which would result in the discharge of any toxic pollutant identified under Section 307 of the Clean Water Act which is not limited in the permit, if that discharge will exceed the highest of the following notification levels:
(1) One hundred micrograms per liter (100 ug/l);
(2) Two hundred micrograms per liter (200 ug/l) for acrolein and acrylonitrile; five hundred micrograms per liter (500 ug/l) for 2,4-dinitrophenol and for 2-methyl-4,6 dinitrophenol; and one milligram per liter (1 mg/l) for antimony.
(3) Five (5) times the maximum concentration value reported for that pollutant in the NPDES permit application; or
(4) The level established by the Agency in this permit.
(b) That they have begun or expect to begin to use or manufacture as an intermediate or final product or byproduct any toxic pollutant which was not reported in the NPDES permit application.

(17) All Publicly Owned Treatment Works (POTWs) must provide adequate notice to the Agency of the following:
(a) Any new introduction of pollutants into that POTW from an indirect discharge which would be subject to Sections 301 or 306 of the Clean Water Act if it were directly discharging those pollutants; and
(b) Any substantial change in the volume or character of pollutants being introduced into that POTW by a source introducing pollutants into the POTW at the time of issuance of the permit.
(c) For purposes of this paragraph, adequate notice shall include information on (i) the quality and quantity of effluent introduced into the POTW, and (ii) any anticipated impact of the change on the quantity or quality of effluent to be discharged from the POTW.

(18) If the permit is issued to a publicly owned or publicly regulated treatment works, the permittee shall require any industrial user of such treatment works to comply with federal requirements concerning:
(a) User charges pursuant to Section 204 (b) of the Clean Water Act, and applicable regulations appearing in 40 CFR 35;
(b) Toxic pollutant effluent standards and pretreatment standards pursuant to Section 307 of the Clean Water Act; and
(c) Inspection, monitoring and entry pursuant to Section 308 of the Clean Water Act.

(Rev 7-9-2010 bah)

(19) If an applicable standard or limitation is promulgated under Section 301(b)(2)(C) and (D), 304(b)(2), or 307(a)(2) and that effluent standard or limitation is more stringent than any effluent limitation in the permit, or controls a pollutant not limited in the permit, the permit shall be promptly modified or revoked, and reissued to conform to that effluent standard or limitation.

(20) Any authorization to construct issued to the permittee pursuant to 35 Ill. Adm. Code 309.154 is hereby incorporated by reference as a condition of this permit.

(21) The permittee shall not make any false statement, representation or certification in any application, record, report, plan or other document submitted to the Agency or the USEPA, or required to be maintained under this permit.

(22) The Clean Water Act provides that any person who violates a permit condition implementing Sections 301, 302, 306, 307, 308, 318, or 405 of the Clean Water Act is subject to a civil penalty not to exceed $25,000 per day of such violation. Any person who willfully or negligently violates permit conditions implementing Sections 301, 302, 306, 307, 308, 318 or 405 of the Clean Water Act is subject to a fine of not less than $2,500 nor more than $25,000 per day of violation, or by imprisonment for not more than one year, or both.
Additional penalties for violating these sections of the Clean Water Act are identified in 40 CFR 122.41 (a)(2) and (3).

(23) The Clean Water Act provides that any person who falsifies, tampers with, or knowingly renders inaccurate any monitoring device or method required to be maintained under this permit shall, upon conviction, be punished by a fine of not more than $10,000, or by imprisonment for not more than 2 years, or both. If a conviction of a person is for a violation committed after a first conviction of such person under this paragraph, punishment is a fine of not more than $20,000 per day of violation, or by imprisonment of not more than 4 years, or both.

(24) The Clean Water Act provides that any person who knowingly makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or non-compliance shall, upon conviction, be punished by a fine of not more than $10,000 per violation, or by imprisonment for not more than 6 months per violation, or by both.

(25) Collected screening, slurries, sludges, and other solids shall be disposed of in such a manner as to prevent entry of those wastes (or runoff from the wastes) into waters of the State. The proper authorization for such disposal shall be obtained from the Agency and is incorporated as part hereof by reference.

(26) In case of conflict between these standard conditions and any other condition(s) included in this permit, the other condition(s) shall govern.

(27) The permittee shall comply with, in addition to the requirements of the permit, all applicable provisions of 35 Ill. Adm. Code, Subtitle C, Subtitle D, Subtitle E, and all applicable orders of the Board or any court with jurisdiction.

(28) The provisions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit is held invalid, the remaining provisions of this permit shall continue in full force and effect.

Illinois Department of
Natural Resources

One Natural Resources Way Springfield, Illinois 62702-1271
http://dnr.state.il.us

Pat Quinn, Governor
Marc Miller, Director

mbb 6/3/14

May 21, 2014

SUBJECT: Application No. S20140125
Clean Water Act Section 401 Certification
LaSalle County Station Units 1 and 2 Operating Licenses
Illinois River, LaSalle County

Michael P. Gallagher
Exelon Generation Company, LLC
200 Exelon Way
Kennett Square, Pennsylvania 19348

Dear Mr. Gallagher:

This concerns your February 4, 2014 application for an Illinois Department of Natural Resources, Office of Water Resources (IDNR/OWR) permit for the subject project.

I understand that you are seeking Clean Water Act Section 401 Certification from the Illinois Environmental Protection Agency. The certification request is associated with your renewal of the LaSalle County Station, Units 1 and 2 operating licenses from the U.S. Nuclear Regulatory Commission. Since no construction is being proposed in connection with the license renewals, an IDNR/OWR permit will not be required.

This determination does not exempt the project from meeting the requirements of any other local, state or federal agency.

Please feel free to contact me at 217/782-4426 if you have any questions or comments.

Sincerely,

Michael L. Diedrichsen

Michael L. Diedrichsen, P.E.
Acting Manager, Downstate Regulatory Programs

MLD:crw
cc: Exelon Corporation (Plant Manager, LaSalle County Station)
Exelon Generation Co., LLC – Warrenville, IL (Roland Beem)
Illinois Environmental Protection Agency (Dan Heacock)

DEPARTMENT OF THE ARMY
CORPS OF ENGINEERS, ROCK ISLAND DISTRICT
PO BOX 2004 CLOCK TOWER BUILDING
ROCK ISLAND, ILLINOIS 61204-2004

REPLY TO
ATTENTION OF

March 10, 2014

Operations Division

SUBJECT: CEMVR-OD-P-2014-0189

Mr. Roland Beem
Manager, Environmental Programs
Exelon Generation Co., LLC
4300 Winfield Rd.
Warrenville, IL 60555

Dear Mr. Roland Beem:

Our office reviewed all information provided to us concerning the proposed license renewal, in Section 21, Township 32 North, Range 5 East, and Section 21, Township 33 N, Range 5 East, LaSalle County, IL.

We determined your project as proposed does not require a Department of the Army (DA) 404 permit. The decision regarding this action is based on information found in the administrative record which documents the District's decision-making process, the basis for the decision, and the final decision. No indication of discharge of dredged or fill material was found to occur in waters of the United States (including wetlands). Therefore, this determination resulted.

You are advised that this determination for your project is valid for five years from the date of this letter. If the project is not completed within this five-year period or your project plans change, you should contact our office for another determination.

Although and individual Department of Army (DA) permit and individual Illinois Environmental Protection Agency 401 certification may not be required for the project, this does not eliminate the requirement that you must still acquire other applicable Federal, state, and local permits. If you have not already coordinated your project with the Illinois Department of Natural Resources – Office of Water Resources, please contact them at 217/782-3863 to determine if a floodplain development permit is required for your project. You may contact the IEPA Facility Evaluation Unit at 217/782-3362 to determine whether additional authorizations are required from the IEPA. Please send any electronic correspondence to EPA.401.bow@illinois.gov.

The Rock Island District Regulatory Branch is committed to providing quality and timely service to our customers. In an effort to improve customer service, please take a moment to complete the attached postcard and return it or go to our Customer Service Survey found on our web site at http://per2.nwp.usace.army.mil/survey.html. (Be sure to select "Rock Island District" under the area entitled: Which Corps office did you deal with?)

Should you have any questions, please contact our Regulatory Branch by letter, or telephone Ms. Jackie Clark at 309/794-5351.

Sincerely,

Donna M. Jones

Donna M. Jones, P.E.
Chief, Enforcement Section
Regulatory Branch

Copies Furnished:

Mr. Mike Diedrichsen, P.E.
Office of Water Resources
IL Department of Natural Resources
One Natural Resources Way
Springfield, Illinois 62702-1271

Mr. Dan Heacock
IL Environmental Protection Agency
Watershed Management Section
Permit Sec. 15
1021 North Grand Avenue East
Post Office Box 19276
Springfield, Illinois 62794-9276
epa.401.bow@illinois.gov (email)

Exelon Corporation
Plant Manager, LaSalle County Station
2601 North 21st Rd.
Marseilles, IL 61341

Appendix C

National Pollutant Discharge Elimination System Permit

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Letter Page

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 North Grand Avenue East, P.O. Box 19276, Springfield, Illinois 62794-9276 • (217) 782-2829
Pat Quinn, Governor   Lisa Bonnett, Director

217/782-0610

July 5, 2013

Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, Illinois 60555

Re: Exelon Generation Company, LLC
LaSalle County Generating Station
NPDES Permit No. IL0048151
Final Permit

Gentlemen:

Attached is the final NPDES Permit for your discharge. The Permit as issued covers discharge limitations, monitoring, and reporting requirements. Failure to meet any portion of the Permit could result in civil and/or criminal penalties. The Illinois Environmental Protection Agency is ready and willing to assist you in interpreting any of the conditions of the Permit as they relate specifically to your discharge.

The Agency received your letter dated June 20, 2013 regarding the draft NPDES permit. Based on the information provided, the Agency has the following response.

1. Special Condition 3D was revised as requested.
2. Special Condition 16, the first paragraph was revised as requested
3. Special Condition 16, the third paragraph was not revised as requested. The change was unnecessary based on the current language.

The Agency has begun a program allowing the submittal of electronic Discharge Monitoring Reports (eDMRs) instead of paper Discharge Monitoring Reports (DMRs). If you are interested in eDMRs, more information can be found on the Agency website, http://epa.state.il.us/water/edmr/index.html. If your facility is not registered in the eDMR program, a supply of preprinted paper DMR Forms for your facility will be sent to you prior to the initiation of DMR reporting under the reissued permit. Additional information and instructions will accompany the preprinted DMRs upon their arrival.

The attached Permit is effective as of the date indicated on the first page of the Permit. Until the effective date of any re-issued Permit, the limitations and conditions of the previously-issued Permit remain in full effect. You have the right to appeal any condition of the Permit to the Illinois Pollution Control Board within a 35 day period following the issuance date.

4302 N. Main St., Rockford, IL 61103 (815)987-7760
595 S. State, Elgin, IL 60123 (847)608-3131
2125 S. First St., Champaign, IL 61820 (217)278-5800
2009 Mall St., Collinsville, IL 62234 (618)346-5120
9511 Harrison St., Des Plaines, IL 60016 (847)294-4000
5407 N. University St., Arbor 113, Peoria, IL 61614 (309)693-5462
2309 W. Main St., Suite 116, Marion, IL 62959 (618)993-7200
100 W. Randolph, Suite 11-300, Chicago, IL 60601 (312)814-6026

Should you have questions concerning the Permit, please contact Leslie Lowry at 217/782-0610.

Sincerely,

Alan Keller

Alan Keller, P.E.
Manager, Permit Section
Division of Water Pollution Control

SAK:DEL:LRL:12030801.daa

Attachment: Final Permit

cc: Records Unit
Compliance Assurance Section
Rockford Region
Billing
USEPA

NPDES Permit No. IL0048151

Illinois Environmental Protection Agency

Division of Water Pollution Control

1021 North Grand Avenue East

Springfield, Illinois 62794-9276

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

Reissued (NPDES) Permit

Expiration Date: July 31, 2018

Issue Date: July 5, 2013
Effective Date: August 1, 2013

Name and Address of Permittee:

Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, Illinois 60555

Facility Name and Address:

Exelon Generation Company, LLC
LaSalle County Generating Station
2601 N. 21st Street
Marseilles, Illinois 61341
(LaSalle County)

Discharge Number and Name:		Receiving Waters:
001	Cooling Pond Blowdown	Illinois River
A01	Demineralizer Regenerant Wastes	
B01	Sewage Treatment Plant Effluent	
C01	Wastewater Treatment System Effluent	
D01	Cooling Water Intake Screen Backwash	
E01	Unit 1 and 2 Radwaste Treatment System Effluent	
F01	Auxiliary Reactor Equipment Cooling and Flushing Water	
G01	North Site Stormwater Runoff	
H01	South Site Stormwater Runoff	
I01	Reverse Osmosis System Reject Water and Greensand Filter Backwash	
002	Illinois River Make-Up Water Intake Screen Backwash	Illinois River

In compliance with the provisions of the Illinois Environmental Protection Act, Title 35 of Ill. Adm. Code, Subtitle C and/or Subtitle D, Chapter 1, and the Clean Water Act (CWA), the above-named permittee is hereby authorized to discharge at the above location to the above-named receiving stream in accordance with the standard conditions and attachments herein.

Permittee is not authorized to discharge after the above expiration date. In order to receive authorization to discharge beyond the expiration date, the permittee shall submit the proper application as required by the Illinois Environmental Protection Agency (IEPA) not later than 180 days prior to the expiration date.

Alan Keller

Alan Keller, P.E.
Manager, Permit Section
Division of Water Pollution Control

SAK:LRL:12030801.daa

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NPDES Permit No. IL0048151

Effluent Limitations and Monitoring

1. From the effective date of this permit until the expiration date, the effluent of the following discharges shall be monitored and limited at all times as follows:

	LOAD LIMITS lbs/day DAF (DMF)		CONCENTRATION LIMITS mg/l			
PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall 001 – Cooling Pond Blowdown*
(Average Flow = 34.9 MGD)

This discharge consists of:

1. Main Condenser Cooling Water
2. Clean Condensate System Flushing and Maintenance (Alternate Route)
3. House Service Water
4. Demineralizer Regenerant Wastes (Outfall A01)
5. Sewage Treatment Plant Effluent (Outfall B01)
6. Wastewater Treatment System Effluent (Outfall C01)
7. Cooling Pond Intake Screen Backwash (Outfall D01)
8. Unit 1 and 2 Radwaste Treatment System Effluent (Outfall E01)
9. Auxiliary Reactor Equipment Cooling and Flushing Water (Outfall F01)
10. North Site Stormwater Runoff (Outfall G01)**
11. South Site Stormwater Runoff (Outfall H01)**
12. Reverse Osmosis System Reject Water and Greensand Filter Backwash (Outfall I01)
13. Water Softener Regenerant Waste
14. North Inlet Canal Stormwater Runoff**
15. South Inlet Canal Stormwater Runoff**
16. IDNR Fish Hatchery Effluents

PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE
Flow (MGD)	See Special Condition 1.				Daily	Continuous
pH	See Special Condition 2.				2/Month	Grab
Temperature	See Special Condition 3.				Daily	Continuous
Total Residual Chlorine / Total Residual Oxidant	See Special Condition 4 and 16.			0.05	2/Month	Grab
Zinc (Total)			Monitor Only		1/Quarter	Grab

* - See Special Condition 13.

** - See Special Condition 8.

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NPDES Permit No. IL0048151

Effluent Limitations and Monitoring

1. From the effective date of this permit until the expiration date, the effluent of the following discharges shall be monitored and limited at all times as follows:

	LOAD LIMITS lbs/day DAF (DMF)		CONCENTRATION LIMITS mg/l			
PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE
Outfall A01 – Demineralizer Regenerant Wastes* (Intermittent Discharge)						
This discharge consists of: 1. Make-Up Demineralizer Regenerant Wastes 2. Off-Specification Demineralized Water 3. Make-Up Demineralizer Maintenance Wastewater 4. Unit Waterbox Vacuum Pump Condensate 5. Radwaste Treatment Acid/Caustic System Drains						
Flow (MGD)	See Special Condition 1.				1/Week	24 Hour Total
Total Suspended Solids			15	30	1/Week	Grab
* - Also discharge to the Wastewater Treatment System (Outfall C01) as an alternate route.						
Outfall B01 – Sewage Treatment Plant Effluent (DAF = 0.06 MGD)						
This discharge consists of: 1. Sanitary Wastewater 2. Eyewash Station Wastewater						
Flow (MGD)	See Special Condition 1.				Daily	Continuous
pH	See Special Condition 2.				2/Month	Grab
$CBOD_5$	13	42	25	50	2/Month	24 Hour Composite
Total Suspended Solids	15	50	30	60	2/Month	24 Hour Composite

NPDES Permit No. IL0048151

Effluent Limitations and Monitoring

1. From the effective date of this permit until the expiration date, the effluent of the following discharges shall be monitored and limited at all times as follows:

	LOAD LIMITS lbs/day DAF (DMF)		CONCENTRATION LIMITS mg/l			
PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall C01 – Wastewater Treatment System Effluent
(DAF = 0.044 MGD)

This discharge consists of:

1. Turbine Building Fire and Miscellaneous Non-Radioactive Wastewater Sump
2. Greensand Filter Backwash (Alternative Route)
3. Diesel Fuel Storage and Service Water Building Sump
4. Auxiliary Boiler Blowdown
5. Water Softener Regenerant Waste
6. Demineralizer Regenerant Wastes (Outfall A01 Alternate Route)
7. Heat Bay Building Roof Area
8. Fire Protection System Flushing and Maintenance*
9. Service Water System Flushing and Maintenance*
10. Domestic Water System Flushing and Maintenance*
11. Clean Condensate System Flushing and Maintenance**
12. Laboratory Liquid Wastes
13. Station Heat System Condensate
14. Diesel Generator Cooling Water
15. Standby Liquid Control Test Skid Flush Water
16. Groundwater

PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE
Flow (MGD)	See Special Condition 1.				Daily	Continuous
pH	See Special Condition 2.				1/Week	Grab
Total Suspended Solids	5	17	15	30	1/Month	24 Hour Composite
Oil & Grease	2.5	3.34	15	20	1/Month	Grab

* - Also discharges to the North Site Stormwater Runoff (Outfall G01) and/or South Site Stormwater Runoff (Outfall H01) as an alternate route.
** - Also discharges to the Cooling Pond Blowdown (Outfall 001) via the service water system and resulting main condenser cooling water as an alternate route.

Outfall D01 – Cooling Water Intake Screen Backwash*
(Intermittent Discharge)

* - This discharge is limited to cooling water intake screen backwash free from other wastewater discharges. Adequate maintenance of the trash basket is required to prevent the discharge of floating debris collected on intake screens back to the cooling pond.

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NPDES Permit No. IL0048151

Effluent Limitations and Monitoring

1. From the effective date of this permit until the expiration date, the effluent of the following discharges shall be monitored and limited at all times as follows:

	LOAD LIMITS lbs/day DAF (DMF)		CONCENTRATION LIMITS mg/l			
PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall E01 – Unit 1 and 2 Radwaste Treatment System Effluent
(Intermittent Discharge)

This discharge consists of:

1. Equipment Drains in the Turbine, Auxiliary, and Reactor Buildings
2. Floor Drains in the Turbine, Auxiliary, and Reactor Buildings
3. Condensate Polisher Waste from the Turbine Building
4. Decontamination and Laundry Waste

PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE
Flow (MGD)	See Special Condition 1.				1/Week	Estimate
Total Suspended Solids			15	30	1/Week	Grab
Oil & Grease			15	20	1/Week	Grab

Outfall F01 – Auxiliary Reactor Equipment Cooling and Flushing Water*
(Intermittent Discharge)

* - This discharge is limited to auxiliary reactor equipment cooling and flushing water free from other wastewater discharges.

Outfall G01 – North Site Stormwater Runoff*
(Intermittent Discharge)

This discharge consists of:

1. Fire Protection System Flushing and Maintenance (Alternate Route)
2. Service Water System Flushing and Maintenance (Alternate Route)
3. Domestic Water System Flushing and Maintenance (Alternate Route)
4. Clean Condensate System Flushing and Maintenance (Alternate Route)
5. North Site Uncontaminated Stormwater Runoff

* - See Special Condition 8.

NPDES Permit No. IL0048151

Effluent Limitations and Monitoring

1. From the effective date of this permit until the expiration date, the effluent of the following discharges shall be monitored and limited at all times as follows:

PARAMETER	LOAD LIMITS lbs/day DAF (DMF) 30 DAY AVERAGE	DAILY MAXIMUM	CONCENTRATION LIMITS mg/l 30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall H01 – South Site Stormwater Runoff*
(Intermittent Discharge)

This discharge consists of:

1. Fire Protection System Flushing and Maintenance (Alternate Route)
2. Service Water System Flushing and Maintenance (Alternate Route)
3. Domestic Water System Flushing and Maintenance (Alternate Route)
4. Clean Condensate System Flushing and Maintenance (Alternate Route)
5. South Site Uncontaminated Stormwater Runoff

* - See Special Condition 8.

Outfall I01 – Reverse Osmosis System Reject Water and Greensand Filter Backwash
(Average Flow = 0.003 MGD)

PARAMETER	30 DAY AVERAGE (lbs/day)	DAILY MAXIMUM (lbs/day)	30 DAY AVERAGE (mg/l)	DAILY MAXIMUM (mg/l)	SAMPLE FREQUENCY	SAMPLE TYPE
Flow (MGD)	See Special Condition 1.				1/Week	24 Hour Total
Total Suspended Solids			15	30	1/Month	Grab

Outfall 002 – Illinois River Makeup Water Intake Screen Backwash*
(Intermittent Discharge)

This discharge consists of:

1. River Intake Screen Backwash
2. Trench Wash Water
3. Process Sampling Discharge
4. Lake Make-Up Pump Gland Leakoff, Coolers, Reliefs, and Min Flow
5. Lake Make-Up Pump Strainer Backwash
6. Air Compressor Receiver and Prefilter Drainage
7. Dewatering Pump Discharge
8. Fire Protection Water
9. River Screen House Switchyard Stormwater Runoff**
10. River Screen House Floor Drains and Roof Drains

* - Adequate maintenance of the intake screen system is required to prevent the discharge of floating debris collected on intake screens back to the Illinois River.
** - See Special Condition 8.

NPDES Permit No. IL0048151

Special Conditions

SPECIAL CONDITION 1. Flow shall be measured in units of Million Gallons per Day (MGD) and reported as a monthly average and a daily maximum on the Discharge Monitoring Report.

SPECIAL CONDITION 2. The pH shall be in the range 6.0 to 9.0. The monthly minimum and monthly maximum values shall be reported on the DMR form.

SPECIAL CONDITION 3. This facility meets the criteria for establishment of a formal mixing zone for thermal discharges pursuant to 35 IAC 302.102. The following mixing zone defines the area and volume of the receiving water body in which mixing is allowed to occur. Water quality standards for temperature listed in table below must be met at every point outside of the mixing zone.

	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
°F	60	60	60	90	90	90	90	90	90	90	90	60
°C	16	16	16	32	32	32	32	32	32	32	32	16

A. The temperature at the edge of the mixing zone should be calculated using the mass balance equation below:

$T_{EDGE} = [0.25 \times (Q_{US} \times T_{US}) + Q_E \times T_E] / (0.25 \times Q_{US} + Q_E)$

Where:

T_{EDGE} = Temperature at the edge of the mixing zone.
Q_{US} = Upstream Flow
T_{US} = Upstream Temperature
Q_E = Effluent Flow
T_E = Temperature of the effluent.

B. There shall be no abnormal temperature changes that may adversely affect aquatic life unless caused by natural conditions. The normal daily and seasonal temperature fluctuations which existed before the addition of heat due to other than natural causes shall be maintained.

C. The maximum temperature rise above natural temperatures shall not exceed 2.8° C (5° F).

D. The water temperature at the edge of the mixing zone defined above shall not exceed the maximum limits in the foregoing table during more than one percent of the hours in the 12 month period ending with any month. Moreover, at no time shall the water temperature at the edge of the mixing zone exceed the maximum limits in the foregoing table by more than 1.7° C (3° F).

E. The monthly maximum value shall be reported on the DMR form.

SPECIAL CONDITION 4. All samples for Total Residual Chlorine / Total Residual Oxidant shall be analyzed by an applicable method contained in 40 CFR 136, equivalent in accuracy to low-level amperometric titration. Any analytical variability of the method used shall be considered when determining the accuracy and precision of the results obtained.

SPECIAL CONDITION 5. There shall be no discharge of complexed metal bearing wastestreams and associated rinses from chemical metal cleaning unless this permit has been modified to include the new discharge.

SPECIAL CONDITION 6. The Permittee shall record monitoring results on Discharge Monitoring Report (DMR) Forms using one such form for each outfall each month.

In the event that an outfall does not discharge during a monthly reporting period, the DMR Form shall be submitted with no discharge indicated.

The Permittee may choose to submit electronic DMRs (eDMRs) instead of mailing paper DMRs to the IEPA. More information, including registration information for the eDMR program, can be obtained on the IEPA website, http://www.epa.state.il.us/water/edmr/index.html.

The completed Discharge Monitoring Report forms shall be submitted to IEPA no later than the 28th day of the following month, unless otherwise specified by the permitting authority.

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NPDES Permit No. IL0048151

Special Conditions

Permittees not using eDMRs shall mail Discharge Monitoring Reports with an original signature to the IEPA at the following address:

Illinois Environmental Protection Agency
Division of Water Pollution Control
1021 North Grand Avenue East
Post Office Box 19276
Springfield, Illinois 62794-9276

Attention: Compliance Assurance Section, Mail Code # 19

SPECIAL CONDITION 7. The upset defense provisions as defined in 40 CFR 122.41(n) are hereby incorporated by reference.

SPECIAL CONDITION 8.

STORM WATER POLLUTION PREVENTION PLAN (SWPPP)

A. A storm water pollution prevention plan shall be maintained by the permittee for the storm water associated with industrial activity at this facility. The plan shall identify potential sources of pollution which may be expected to affect the quality of storm water discharges associated with the industrial activity at the facility. In addition, the plan shall describe and ensure the implementation of practices which are to be used to reduce the pollutants in storm water discharges associated with industrial activity at the facility and to assure compliance with the terms and conditions of this permit. The permittee shall modify the plan if substantive changes are made or occur affecting compliance with this condition.

1. Waters not classified as impaired pursuant to Section 303(d) of the Clean Water Act.

   Unless otherwise specified by federal regulation, the storm water pollution prevention plan shall be designed for a storm event equal to or greater than a 25-year 24-hour rainfall event.

2. Waters classified as impaired pursuant to Section 303(d) of the Clean Water Act.

   For any site which discharges directly to an impaired water identified in the Agency's 303(d) listing, and if any parameter in the subject discharge has been identified as the cause of impairment, the storm water pollution prevention plan shall be designed for a storm event equal to or greater than a 25-year 24-hour rainfall event. If required by federal regulations, the storm water pollution prevention plan shall adhere to a more restrictive design criteria.

B. The operator or owner of the facility shall make a copy of the plan available to the Agency at any reasonable time upon request.

Facilities which discharge to a municipal separate storm sewer system shall also make a copy available to the operator of the municipal system at any reasonable time upon request.

C. The permittee may be notified by the Agency at any time that the plan does not meet the requirements of this condition. After such notification, the permittee shall make changes to the plan and shall submit a written certification that the requested changes have been made. Unless otherwise provided, the permittee shall have 30 days after such notification to make the changes.

D. The discharger shall amend the plan whenever there is a change in construction, operation, or maintenance which may affect the discharge of significant quantities of pollutants to the waters of the State or if a facility inspection required by paragraph H of this condition indicates that an amendment is needed. The plan should also be amended if the discharger is in violation of any conditions of this permit, or has not achieved the general objective of controlling pollutants in storm water discharges. Amendments to the plan shall be made within 30 days of any proposed construction or operational changes at the facility, and shall be provided to the Agency for review upon request.

E. The plan shall provide a description of potential sources which may be expected to add significant quantities of pollutants to storm water discharges, or which may result in non-storm water discharges from storm water outfalls at the facility. The plan shall include, at a minimum, the following items:

1. A topographic map extending one-quarter mile beyond the property boundaries of the facility, showing: the facility, surface water bodies, wells (including injection wells), seepage pits, infiltration ponds, and the discharge points where the facility's storm water discharges to a municipal storm drain system or other water body. The requirements of this paragraph may be included on the site map if appropriate. Any map or portion of map may be withheld for security reasons.

2. A site map showing:

   i. The storm water conveyance and discharge structures;

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ii. An outline of the storm water drainage areas for each storm water discharge point;

iii. Paved areas and buildings;

iv. Areas used for outdoor manufacturing, storage, or disposal of significant materials, including activities that generate significant quantities of dust or particulates.

v. Location of existing storm water structural control measures (dikes, coverings, detention facilities, etc.);

vi. Surface water locations and/or municipal storm drain locations

vii. Areas of existing and potential soil erosion;

viii. Vehicle service areas;

ix. Material loading, unloading, and access areas.

x. Areas under items iv and ix above may be withheld from the site for security reasons.

3. A narrative description of the following:

   i. The nature of the industrial activities conducted at the site, including a description of significant materials that are treated, stored or disposed of in a manner to allow exposure to storm water;

   ii. Materials, equipment, and vehicle management practices employed to minimize contact of significant materials with storm water discharges;

   iii. Existing structural and non-structural control measures to reduce pollutants in storm water discharges;

   iv. Industrial storm water discharge treatment facilities;

   v. Methods of onsite storage and disposal of significant materials.

4. A list of the types of pollutants that have a reasonable potential to be present in storm water discharges in significant quantities. Also provide a list of any pollutant that is listed as impaired in the most recent 303(d) report.

5. An estimate of the size of the facility in acres or square feet, and the percent of the facility that has impervious areas such as pavement or buildings.

6. A summary of existing sampling data describing pollutants in storm water discharges.

F. The plan shall describe the storm water management controls which will be implemented by the facility. The appropriate controls shall reflect identified existing and potential sources of pollutants at the facility. The description of the storm water management controls shall include:

1. Storm Water Pollution Prevention Personnel - Identification by job titles of the individuals who are responsible for developing, implementing, and revising the plan.

2. Preventive Maintenance - Procedures for inspection and maintenance of storm water conveyance system devices such as oil/water separators, catch basins, etc., and inspection and testing of plant equipment and systems that could fail and result in discharges of pollutants to storm water.

3. Good Housekeeping - Good housekeeping requires the maintenance of clean, orderly facility areas that discharge storm water. Material handling areas shall be inspected and cleaned to reduce the potential for pollutants to enter the storm water conveyance system.

4. Spill Prevention and Response - Identification of areas where significant materials can spill into or otherwise enter the storm water conveyance systems and their accompanying drainage points. Specific material handling procedures, storage requirements, spill cleanup equipment and procedures should be identified, as appropriate. Internal notification procedures for spills of significant materials should be established.

5. Storm Water Management Practices - Storm water management practices are practices other than those which control the source of pollutants. They include measures such as installing oil and grit separators, diverting storm water into retention

basins, etc. Based on assessment of the potential of various sources to contribute pollutants, measures to remove pollutants from storm water discharge shall be implemented. In developing the plan, the following management practices shall be considered:

i. Containment - Storage within berms or other secondary containment devices to prevent leaks and spills from entering storm water runoff. To the maximum extent practicable storm water discharged from any area where material handling equipment or activities, raw material, intermediate products, final products, waste materials, by-products, or industrial machinery are exposed to storm water should not enter vegetated areas or surface waters or infiltrate into the soil unless adequate treatment is provided.

ii. Oil & Grease Separation - Oil/water separators, booms, skimmers or other methods to minimize oil contaminated storm water discharges.

iii. Debris & Sediment Control - Screens, booms, sediment ponds or other methods to reduce debris and sediment in storm water discharges.

iv. Waste Chemical Disposal - Waste chemicals such as antifreeze, degreasers and used oils shall be recycled or disposed of in an approved manner and in a way which prevents them from entering storm water discharges.

v. Storm Water Diversion - Storm water diversion away from materials manufacturing, storage and other areas of potential storm water contamination. Minimize the quantity of storm water entering areas where material handling equipment of activities, raw material, intermediate products, final products, waste materials, by-products, or industrial machinery are exposed to storm water using green infrastructure techniques where practicable in the areas outside the exposure area, and otherwise divert storm water away from exposure area.

vi. Covered Storage or Manufacturing Areas - Covered fueling operations, materials manufacturing and storage areas to prevent contact with storm water.

vii. Storm Water Reduction - Install vegetation on roofs of buildings within adjacent to the exposure area to detain and evapotranspirate runoff where precipitation falling on the roof is not exposed to contaminants, to minimize storm water runoff; capture storm water in devices that minimize the amount of storm water runoff and use this water as appropriate based on quality.

6. Sediment and Erosion Prevention - The plan shall identify areas which due to topography, activities, or other factors, have a high potential for significant soil erosion. The plan shall describe measures to limit erosion.

7. Employee Training - Employee training programs shall inform personnel at all levels of responsibility of the components and goals of the storm water pollution control plan. Training should address topics such as spill response, good housekeeping and material management practices. The plan shall identify periodic dates for such training.

8. Inspection Procedures - Qualified plant personnel shall be identified to inspect designated equipment and plant areas. A tracking or follow-up procedure shall be used to ensure appropriate response has been taken in response to an inspection. Inspections and maintenance activities shall be documented and recorded.

G. Non-Storm Water Discharge - The plan shall include a certification that the discharge has been tested or evaluated for the presence of non-storm water discharge. The certification shall include a description of any test for the presence of non-storm water discharges, the methods used, the dates of the testing, and any onsite drainage points that were observed during the testing. Any facility that is unable to provide this certification must describe the procedure of any test conducted for the presence of non-storm water discharges, the test results, potential sources of non-storm water discharges to the storm sewer, and why adequate tests for such storm sewers were not feasible.

H. Quarterly Visual Observation of Discharges - The requirements and procedures for quarterly visual observations are applicable to all outfalls covered by this condition.

1. You must perform and document a quarterly visual observation of a storm water discharge associated with industrial activity from each outfall. The visual observation must be made during daylight hours. If no storm event resulted in runoff during daylight hours from the facility during a monitoring quarter, you are excused from the visual observations requirement for that quarter, provided you document in your records that no runoff occurred. You must sign and certify the document.

2. Your visual observation must be made on samples collected as soon as practical, but not to exceed 1 hour or when the runoff or snow melt begins discharging from your facility. All samples must be collected from a storm event discharge that is greater than 0.1 inch in magnitude and that occurs at least 72 hours from the previously measureable (greater than 0.1 inch rainfall) storm event. The observation must document: color, odor, clarity, floating solids, settled solids, suspended solids, foam, oil

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sheen, and other obvious indicators of storm water pollution. If visual observations indicate any unnatural color, odor, turbidity, floatable material, oil sheen or other indicators of storm water pollution, the permittee shall obtain a sample and monitor for the parameter or the list of pollutants in Part E.4.

3. You must maintain your visual observation reports onsite with the SWPPP. The report must include the observation date and time, inspection personnel, nature of the discharge (i.e., runoff or snow melt), visual quality of the storm water discharge (including observations of color, odor, floating solids, settled solids, suspended solids, foam, oil sheen, and other obvious indicators of storm water pollution), and probable sources of any observed storm water contamination.

4. You may exercise a waiver of the visual observation requirement at a facility that is inactive or unstaffed, as long as there are no industrial materials or activities exposed to storm water. If you exercise this waiver, you must maintain a certification with your SWPPP stating that the site is inactive and unstaffed, and that there are no industrial materials or activities exposed to storm water.

5. Representative Outfalls - If your facility has two or more outfalls that you believe discharge substantially identical effluents, based on similarities of the industrial activities, significant materials, size of drainage areas, and storm water management practices occurring within the drainage areas of the outfalls, you may conduct visual observations of the discharge at just one of the outfalls and report that the results also apply to the substantially identical outfall(s).

6. The visual observation documentation shall be made available to the Agency and general public upon written request.

I. The permittee shall conduct an annual facility inspection to verify that all elements of the plan, including the site map, potential pollutant sources, and structural and non-structural controls to reduce pollutants in industrial storm water discharges are accurate. Observations that require a response and the appropriate response to the observation shall be retained as part of the plan. Records documenting significant observations made during the site inspection shall be submitted to the Agency in accordance with the reporting requirements of this permit.

J. This plan should briefly describe the appropriate elements of other program requirements, including Spill Prevention Control and Countermeasures (SPCC) plans required under Section 311 of the CWA and the regulations promulgated there under, and Best Management Programs under 40 CFR 125.100.

K. The plan is considered a report that shall be available to the public at any reasonable time upon request.

L. The plan shall include the signature and title of the person responsible for preparation of the plan and include the date of initial preparation and each amendment thereto.

M. Facilities which discharge storm water associated with industrial activity to municipal separate storm sewers may also be subject to additional requirement imposed by the operator of the municipal system

Construction Authorization

Authorization is hereby granted to construct treatment works and related equipment that may be required by the Storm Water Pollution Prevention Plan developed pursuant to this permit.

This Authorization is issued subject to the following condition(s).

N. If any statement or representation is found to be incorrect, this authorization may be revoked and the permittee there upon waives all rights there under.

O. The issuance of this authorization (a) does not release the permittee from any liability for damage to persons or property caused by or resulting from the installation, maintenance or operation of the proposed facilities; (b) does not take into consideration the structural stability of any units or part of this project; and (c) does not release the permittee from compliance with other applicable statutes of the State of Illinois, or other applicable local law, regulations or ordinances.

P. Plans and specifications of all treatment equipment being included as part of the stormwater management practice shall be included in the SWPPP.

Q. Construction activities which result from treatment equipment installation, including clearing, grading and excavation activities which result in the disturbance of one acre or more of land area, are not covered by this authorization. The permittee shall contact the IEPA regarding the required permit(s).

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R. The facility shall submit an electronic copy of the annual inspection report to the Illinois Environmental Protection Agency. The report shall include results of the annual facility inspection which is required by Part I of this condition. The report shall also include documentation of any event (spill, treatment unit malfunction, etc.) which would require an inspection, results of the inspection, and any subsequent corrective maintenance activity. The report shall be completed and signed by the authorized facility employee(s) who conducted the inspection(s). The annual inspection report is considered a public document that shall be available at any reasonable time upon request.

S. The first report shall contain information gathered during the one year time period beginning with the effective date of coverage under this permit and shall be submitted no later than 60 days after this one year period has expired. Each subsequent report shall contain the previous year's information and shall be submitted no later than one year after the previous year's report was due.

T. If the facility performs inspections more frequently than required by this permit, the results shall be included as additional information in the annual report.

U. The permittee shall retain the annual inspection report on file at least 3 years. This period may be extended by request of the Illinois Environmental Protection Agency at any time.

Annual inspection reports shall be mailed to the following address:

Illinois Environmental Protection Agency
Bureau of Water
Compliance Assurance Section
Annual Inspection Report
1021 North Grand Avenue East
Post Office Box 19276
Springfield, Illinois 62794-9276

V. The permittee shall notify any regulated small municipal separate storm sewer owner (MS4 Community) that they maintain coverage under an individual NPDES permit. The permittee shall submit any SWPPP or any annual inspection to the MS4 community upon request by the MS4 community.

SPECIAL CONDITION 9. This permit authorizes the use of water treatment additives that were requested as part of this renewal. The use of any new additives, or change in those previously approved by the Agency, or if the permittee increases the feed rate or quantity of the additives used beyond what has been approved by the Agency, the permittee shall request a modification of this permit in accordance with the Standard Conditions - Attachment H.

The permittee shall submit to the Agency on a yearly basis a report summarizing their efforts with water treatment suppliers to find a suitable alternative to phosphorus based additives.

SPECIAL CONDITION 10. This permit may be modified to include different final effluent limitations or requirements which are consistent with applicable laws, regulations, or judicial orders. The Agency will public notice the permit modification.

SPECIAL CONDITION 11. The effluent, alone or in combination with other sources, shall not cause a violation of any applicable water quality standard outlined in 35 Ill. Adm. Code 302.

SPECIAL CONDITION 12. The use or operation of this facility shall be by or under the supervision of a Certified Class K operator.

SPECIAL CONDITION 13. There shall be no discharge of polychlorinated biphenyl compounds (PCBs).

SPECIAL CONDITION 14. Samples taken in compliance with the effluent monitoring requirements shall be taken at a point representative of the discharge, but prior to entry into the receiving stream.

SPECIAL CONDITION 15. The facility utilizes a closed-cycle recirculating cooling system, a 2058 acre cooling pond, for cooling of plant condensers and is determined to be the equivalent of Best Technology Available (BTA) for cooling water intake structures to prevent/minimize impingement mortality in accordance with the Best Professional Judgment (BPJ) provisions of 40 CFR 125.3 because it allows the facility to only withdraw the amount of water necessary to maintain the cooling pond level rather than the entire volume used for cooling of the plant condensers.

In order for the Agency to evaluate the potential impacts of cooling water intake structure operations pursuant to 40 CFR 125.90(b), the permittee shall prepare and submit information to the Agency outlining current intake structure conditions at this facility, including a detailed description of the current intake structure operation and design, description of any operational or structural modifications from original design parameters, source waterbody flow information as necessary.

The information shall also include a summary of historical 316(b) related intake impingement and/or entrainment studies, if any, as well as current impingement mortality and/or entrainment characterization data; and shall be submitted to the Agency within six (6) months of the permit's effective date.

Upon the receipt and review of this information, the permit may be modified to require the submittal of additional information based on a Best Professional Judgment review by the Agency. This permit may also be revised or modified in accordance with any laws, regulations, or judicial orders pursuant to Section 316(b) of the Clean Water Act.

SPECIAL CONDITION 16. For a period of 18 months following the effective date of this permit during times when the condenser cooling water is chlorinated intermittently, Total Residual Chlorine may be discharged from each generating unit's main condensers for no more than 2 hours per day. During such authorized discharge time period, the maximum discharge limit is 0.2 mg/l, measured as an instantaneous maximum.

A Total Residual Chlorine limit of 0.05 mg/l (Daily Maximum) for outfall 001 shall become effective 18 months from the effective date of this Permit.

The Permittee shall construct a dechlorination system or some alternative means of compliance in accordance with the following schedule:

1. Status Report	4 months from the effective date
2. Commence Construction	10 months from the effective date
3. Status Report	14 months from the effective date
4. Complete Construction	16 months from the effective date
5. Obtain Operation Level	18 months from the effective date

Compliance dates set out in this Permit may be superseded or supplemented by compliance dates in judicial orders, or Pollution Control Board orders. This Permit may be modified, with Public Notice, to include such revised compliance dates.

The Permittee shall operate the dechlorination system or an alternative means of compliance in a manner to ensure continuous compliance with the Total Residual Chlorine limit, not to the extent that will result in violations of other permitted effluent characteristic, or water quality standards.

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The Permittee shall submit a report no later than fourteen (14) days following the completion dates indicated above for each numbered item in the compliance schedule, indicating, a) the date the item was completed, or b) that the item was not completed, the reason for non-completion, and the anticipated completion date.

Attachment H

Standard Conditions

Definitions

Act means the Illinois Environmental Protection Act, 415 ILCS 5 as Amended.

Agency means the Illinois Environmental Protection Agency.

Board means the Illinois Pollution Control Board.

Clean Water Act (formerly referred to as the Federal Water Pollution Control Act) means Pub. L 92-500, as amended. 33 U.S.C. 1251 et seq.

NPDES (National Pollutant Discharge Elimination System) means the national program for issuing, modifying, revoking and reissuing, terminating, monitoring and enforcing permits, and imposing and enforcing pretreatment requirements, under Sections 307, 402, 318 and 405 of the Clean Water Act.

USEPA means the United States Environmental Protection Agency.

Daily Discharge means the discharge of a pollutant measured during a calendar day or any 24-hour period that reasonably represents the calendar day for purposes of sampling. For pollutants with limitations expressed in units of mass, the "daily discharge" is calculated as the total mass of the pollutant discharged over the day. For pollutants with limitations expressed in other units of measurements, the "daily discharge" is calculated as the average measurement of the pollutant over the day.

Maximum Daily Discharge Limitation (daily maximum) means the highest allowable daily discharge.

Average Monthly Discharge Limitation (30 day average) means the highest allowable average of daily discharges over a calendar month, calculated as the sum of all daily discharges measured during a calendar month divided by the number of daily discharges measured during that month.

Average Weekly Discharge Limitation (7 day average) means the highest allowable average of daily discharges over a calendar week, calculated as the sum of all daily discharges measured during a calendar week divided by the number of daily discharges measured during that week.

Best Management Practices (BMPs) means schedules of activities, prohibitions of practices, maintenance procedures, and other management practices to prevent or reduce the pollution of waters of the State. BMPs also include treatment requirements, operating procedures, and practices to control plant site runoff, spillage or leaks, sludge or waste disposal, or drainage from raw material storage.

Aliquot means a sample of specified volume used to make up a total composite sample.

Grab Sample means an individual sample of at least 100 milliliters collected at a randomly-selected time over a period not exceeding 15 minutes.

24-Hour Composite Sample means a combination of at least 8 sample aliquots of at least 100 milliliters, collected at periodic intervals during the operating hours of a facility over a 24-hour period.

8-Hour Composite Sample means a combination of at least 3 sample aliquots of at least 100 milliliters, collected at periodic intervals during the operating hours of a facility over an 8-hour period.

Flow Proportional Composite Sample means a combination of sample aliquots of at least 100 milliliters collected at periodic intervals such that either the time interval between each aliquot or the volume of each aliquot is proportional to either the stream flow at the time of sampling or the total stream flow since the collection of the previous aliquot.

(1) **Duty to comply.** The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Act and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application. The permittee shall comply with effluent standards or prohibitions established under Section 307(a) of the Clean Water Act for toxic pollutants within the time provided in the regulations that establish these standards or prohibitions, even if the permit has not yet been modified to incorporate the requirements.

(2) **Duty to reapply.** If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must apply for and obtain a new permit. If the permittee submits a proper application as required by the Agency no later than 180 days prior to the expiration date, this permit shall continue in full force and effect until the final Agency decision on the application has been made.

(3) **Need to halt or reduce activity not a defense.** It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

(4) **Duty to mitigate.** The permittee shall take all reasonable steps to minimize or prevent any discharge in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment.

(5) **Proper operation and maintenance.** The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up, or auxiliary facilities, or similar systems only when necessary to achieve compliance with the conditions of the permit.

(6) **Permit actions.** This permit may be modified, revoked and reissued, or terminated for cause by the Agency pursuant to 40 CFR 122.62 and 40 CFR 122.63. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

(7) **Property rights.** This permit does not convey any property rights of any sort, or any exclusive privilege.

(8) **Duty to provide information.** The permittee shall furnish to the Agency within a reasonable time, any information which the Agency may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also furnish to the Agency upon request, copies of records required to be kept by this permit.

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(9) **Inspection and entry.** The permittee shall allow an authorized representative of the Agency or USEPA (including an authorized contractor acting as a representative of the Agency or USEPA), upon the presentation of credentials and other documents as may be required by law, to:
   (a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;
   (b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;
   (c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and
   (d) Sample or monitor at reasonable times, for the purpose of assuring permit compliance, or as otherwise authorized by the Act, any substances or parameters at any location.

(10) **Monitoring and records.**
   (a) Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.
   (b) The permittee shall retain records of all monitoring information, including all calibration and maintenance records, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least 3 years from the date of this permit, measurement, report or application. Records related to the permittee's sewage sludge use and disposal activities shall be retained for a period of at least five years (or longer as required by 40 CFR Part 503). This period may be extended by request of the Agency or USEPA at any time.
   (c) Records of monitoring information shall include:
      (1) The date, exact place, and time of sampling or measurements;
      (2) The individual(s) who performed the sampling or measurements;
      (3) The date(s) analyses were performed;
      (4) The individual(s) who performed the analyses;
      (5) The analytical techniques or methods used; and
      (6) The results of such analyses.
   (d) Monitoring must be conducted according to test procedures approved under 40 CFR Part 136, unless other test procedures have been specified in this permit. Where no test procedure under 40 CFR Part 136 has been approved, the permittee must submit to the Agency a test method for approval. The permittee shall calibrate and perform maintenance procedures on all monitoring and analytical instrumentation at intervals to ensure accuracy of measurements.

(11) **Signatory requirement.** All applications, reports or information submitted to the Agency shall be signed and certified.
   (a) **Application.** All permit applications shall be signed as follows:
      (1) For a corporation: by a principal executive officer of at least the level of vice president or a person or position having overall responsibility for environmental matters for the corporation:
      (2) For a partnership or sole proprietorship: by a general partner or the proprietor, respectively; or
      (3) For a municipality, State, Federal, or other public agency: by either a principal executive officer or ranking elected official.
   (b) **Reports.** All reports required by permits, or other information requested by the Agency shall be signed by a person described in paragraph (a) or by a duly authorized representative of that person. A person is a duly authorized representative only if:
      (1) The authorization is made in writing by a person described in paragraph (a); and
      (2) The authorization specifies either an individual or a position responsible for the overall operation of the facility, from which the discharge originates, such as a plant manager, superintendent or person of equivalent responsibility; and
      (3) The written authorization is submitted to the Agency.
   (c) **Changes of Authorization.** If an authorization under (b) is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of (b) must be submitted to the Agency prior to or together with any reports, information, or applications to be signed by an authorized representative.
   (d) **Certification.** Any person signing a document under paragraph (a) or (b) of this section shall make the following certification:

   I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

(12) **Reporting requirements.**
   (a) **Planned changes.** The permittee shall give notice to the Agency as soon as possible of any planned physical alterations or additions to the permitted facility.
   Notice is required when:
      (1) The alteration or addition to a permitted facility may meet one of the criteria for determining whether a facility is a new source pursuant to 40 CFR 122.29 (b); or
      (2) The alteration or addition could significantly change the nature or increase the quantity of pollutants discharged. This notification applies to pollutants which are subject neither to effluent limitations in the permit, nor to notification requirements pursuant to 40 CFR 122.42 (a)(1).
      (3) The alteration or addition results in a significant change in the permittee's sludge use or disposal practices, and such alteration, addition, or change may justify the application of permit conditions that are different from or absent in the existing permit, including notification of additional use or disposal sites not reported during the permit application process or not reported pursuant to an approved land application plan.
   (b) **Anticipated noncompliance.** The permittee shall give advance notice to the Agency of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.
   (c) **Transfers.** This permit is not transferable to any person except after notice to the Agency.
   (d) **Compliance schedules.** Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 14 days following each schedule date.
   (e) **Monitoring reports.** Monitoring results shall be reported at the intervals specified elsewhere in this permit.
      (1) Monitoring results must be reported on a Discharge Monitoring Report (DMR).

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(2) If the permittee monitors any pollutant more frequently than required by the permit, using test procedures approved under 40 CFR 136 or as specified in the permit, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

(3) Calculations for all limitations which require averaging of measurements shall utilize an arithmetic mean unless otherwise specified by the Agency in the permit.

(f) **Twenty-four hour reporting.** The permittee shall report any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24-hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within 5 days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and time; and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The following shall be included as information which must be reported within 24-hours:

(1) Any unanticipated bypass which exceeds any effluent limitation in the permit.

(2) Any upset which exceeds any effluent limitation in the permit.

(3) Violation of a maximum daily discharge limitation for any of the pollutants listed by the Agency in the permit or any pollutant which may endanger health or the environment.

The Agency may waive the written report on a case-by-case basis if the oral report has been received within 24-hours.

(g) **Other noncompliance.** The permittee shall report all instances of noncompliance not reported under paragraphs (12) (d), (e), or (f), at the time monitoring reports are submitted. The reports shall contain the information listed in paragraph (12) (f).

(h) **Other information.** Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application, or in any report to the Agency, it shall promptly submit such facts or information.

(13) **Bypass.**

(a) Definitions.

(1) Bypass means the intentional diversion of waste streams from any portion of a treatment facility.

(2) Severe property damage means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

(b) Bypass not exceeding limitations. The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it also is for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of paragraphs (13)(c) and (13)(d).

(c) Notice.

(1) Anticipated bypass. If the permittee knows in advance of the need for a bypass, it shall submit prior notice, if possible at least ten days before the date of the bypass.

(2) Unanticipated bypass. The permittee shall submit notice of an unanticipated bypass as required in paragraph (12)(f) (24-hour notice).

(d) Prohibition of bypass.

(1) Bypass is prohibited, and the Agency may take enforcement action against a permittee for bypass, unless:

(i) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(ii) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and

(iii) The permittee submitted notices as required under paragraph (13)(c).

(2) The Agency may approve an anticipated bypass, after considering its adverse effects, if the Agency determines that it will meet the three conditions listed above in paragraph (13)(d)(1).

(14) **Upset.**

(a) Definition. Upset means an exceptional incident in which there is unintentional and temporary noncompliance with technology based permit effluent limitations because of factors beyond the reasonable control of the permittee. An upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation.

(b) Effect of an upset. An upset constitutes an affirmative defense to an action brought for noncompliance with such technology based permit effluent limitations if the requirements of paragraph (14)(c) are met. No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

(c) Conditions necessary for a demonstration of upset. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs, or other relevant evidence that:

(1) An upset occurred and that the permittee can identify the cause(s) of the upset;

(2) The permitted facility was at the time being properly operated; and

(3) The permittee submitted notice of the upset as required in paragraph (12)(f)(2) (24-hour notice).

(4) The permittee complied with any remedial measures required under paragraph (4).

(d) Burden of proof. In any enforcement proceeding the permittee seeking to establish the occurrence of an upset has the burden of proof.

(15) **Transfer of permits.** Permits may be transferred by modification or automatic transfer as described below:

(a) Transfers by modification. Except as provided in paragraph (b), a permit may be transferred by the permittee to a new owner or operator only if the permit has been modified or revoked and reissued pursuant to 40 CFR 122.62 (b) (2), or a minor modification made pursuant to 40 CFR 122.63 (d), to identify the new permittee and incorporate such other requirements as may be necessary under the Clean Water Act.

(b) Automatic transfers. As an alternative to transfers under paragraph (a), any NPDES permit may be automatically

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transferred to a new permittee if:
(1) The current permittee notifies the Agency at least 30 days in advance of the proposed transfer date;
(2) The notice includes a written agreement between the existing and new permittees containing a specified date for transfer of permit responsibility, coverage and liability between the existing and new permittees; and
(3) The Agency does not notify the existing permittee and the proposed new permittee of its intent to modify or revoke and reissue the permit. If this notice is not received, the transfer is effective on the date specified in the agreement.

(16) All manufacturing, commercial, mining, and silvicultural dischargers must notify the Agency as soon as they know or have reason to believe:
(a) That any activity has occurred or will occur which would result in the discharge of any toxic pollutant identified under Section 307 of the Clean Water Act which is not limited in the permit, if that discharge will exceed the highest of the following notification levels:
(1) One hundred micrograms per liter (100 ug/l);
(2) Two hundred micrograms per liter (200 ug/l) for acrolein and acrylonitrile; five hundred micrograms per liter (500 ug/l) for 2,4-dinitrophenol and for 2-methyl-4,6 dinitrophenol; and one milligram per liter (1 mg/l) for antimony.
(3) Five (5) times the maximum concentration value reported for that pollutant in the NPDES permit application; or
(4) The level established by the Agency in this permit.
(b) That they have begun or expect to begin to use or manufacture as an intermediate or final product or byproduct any toxic pollutant which was not reported in the NPDES permit application.

(17) All Publicly Owned Treatment Works (POTWs) must provide adequate notice to the Agency of the following:
(a) Any new introduction of pollutants into that POTW from an indirect discharge which would be subject to Sections 301 or 306 of the Clean Water Act if it were directly discharging those pollutants; and
(b) Any substantial change in the volume or character of pollutants being introduced into that POTW by a source introducing pollutants into the POTW at the time of issuance of the permit.
(c) For purposes of this paragraph, adequate notice shall include information on (i) the quality and quantity of effluent introduced into the POTW, and (ii) any anticipated impact of the change on the quantity or quality of effluent to be discharged from the POTW.

(18) If the permit is issued to a publicly owned or publicly regulated treatment works, the permittee shall require any industrial user of such treatment works to comply with federal requirements concerning:
(a) User charges pursuant to Section 204 (b) of the Clean Water Act, and applicable regulations appearing in 40 CFR 35;
(b) Toxic pollutant effluent standards and pretreatment standards pursuant to Section 307 of the Clean Water Act; and
(c) Inspection, monitoring and entry pursuant to Section 308 of the Clean Water Act.

(Rev. 7-9-2010 bah)

(19) If an applicable standard or limitation is promulgated under Section 301(b)(2)(C) and (D), 304(b)(2), or 307(a)(2) and that effluent standard or limitation is more stringent than any effluent limitation in the permit, or controls a pollutant not limited in the permit, the permit shall be promptly modified or revoked, and reissued to conform to that effluent standard or limitation.

(20) Any authorization to construct issued to the permittee pursuant to 35 Ill. Adm. Code 309.154 is hereby incorporated by reference as a condition of this permit.

(21) The permittee shall not make any false statement, representation or certification in any application, record, report, plan or other document submitted to the Agency or the USEPA, or required to be maintained under this permit.

(22) The Clean Water Act provides that any person who violates a permit condition implementing Sections 301, 302, 306, 307, 308, 318, or 405 of the Clean Water Act is subject to a civil penalty not to exceed $25,000 per day of such violation. Any person who willfully or negligently violates permit conditions implementing Sections 301, 302, 306, 307, 308, 318 or 405 of the Clean Water Act is subject to a fine of not less than $2,500 nor more than $25,000 per day of violation, or by imprisonment for not more than one year, or both.
Additional penalties for violating these sections of the Clean Water Act are identified in 40 CFR 122.41 (a)(2) and (3).

(23) The Clean Water Act provides that any person who falsifies, tampers with, or knowingly renders inaccurate any monitoring device or method required to be maintained under this permit shall, upon conviction, be punished by a fine of not more than $10,000, or by imprisonment for not more than 2 years, or both. If a conviction of a person is for a violation committed after a first conviction of such person under this paragraph, punishment is a fine of not more than $20,000 per day of violation, or by imprisonment of not more than 4 years, or both.

(24) The Clean Water Act provides that any person who knowingly makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or non-compliance shall, upon conviction, be punished by a fine of not more than $10,000 per violation, or by imprisonment for not more than 6 months per violation, or by both.

(25) Collected screening, slurries, sludges, and other solids shall be disposed of in such a manner as to prevent entry of those wastes (or runoff from the wastes) into waters of the State. The proper authorization for such disposal shall be obtained from the Agency and is incorporated as part hereof by reference.

(26) In case of conflict between these standard conditions and any other condition(s) included in this permit, the other condition(s) shall govern.

(27) The permittee shall comply with, in addition to the requirements of the permit, all applicable provisions of 35 Ill. Adm. Code, Subtitle C, Subtitle D, Subtitle E, and all applicable orders of the Board or any court with jurisdiction.

(28) The provisions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit is held invalid, the remaining provisions of this permit shall continue in full force and effect.

Appendix D

Special Status Species Correspondence

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Exelon Generation

Michael P. Gallagher

March 7, 2014

Mr. Richard Nelson
U.S. Fish and Wildlife Service
Rock Island Field Office
1511 47th Avenue
Moline, Il 61265

SUBJECT: Exelon Generation Company, LLC – LaSalle County Station Units 1 and 2 License Renewal Project. Request for Information on Listed Species and Sensitive Habitats – LaSalle County

Dear Mr. Nelson:

Exelon Generation Company, LLC (Exelon) plans to apply to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for LaSalle County Station (LaSalle) Units 1 and 2 no later than January 2015. The existing operating license for Unit 1 will expire on April 17, 2022, and the existing operating license for Unit 2 will expire on December 16, 2023. Renewed licenses would allow LaSalle Units 1 and 2 to operate until 2042 and 2043, respectively.

As part of the license renewal process, the NRC requires (10 CFR 51.53(c)(3)(ii)(E)) that the LaSalle license renewal application include an environmental report assessing the impacts from license renewal activities on species listed or proposed for listing as threatened or endangered in accordance with the Endangered Species Act (ESA) (16 USC 1531, et seq.) and on important plant and animal habitats, including critical habitats as defined by the ESA and essential fish habitat as identified under the Magnuson-Stevens Fishery Conservation and Management Act (16 USC 1801. et seq.). Because no species with essential fish habitat is found in Illinois, this letter seeks input from the U.S. Fish and Wildlife Service (USFWS) regarding effects on species and habitats protected under the ESA only that are in the vicinity of LaSalle, including along the right-of-way (ROW) for the cooling water makeup and blowdown pipelines between the LaSalle cooling pond and the Illinois River.

In June 2013, the NRC revised its regulations at 10 CFR Part 51 such that no transmission line ROW associated with LaSalle requires assessment for environmental impacts from license renewal activities.

Project Features

LaSalle is located in northeastern Illinois, about 75 miles southwest of Chicago, in LaSalle County. The property is approximately 6 miles southwest of Seneca and 7 miles south-southeast of Marseilles, as shown in the attached Figure 1. The area surrounding LaSalle is relatively flat, and is rural and agricultural. Numerous wind turbines operate in the immediate vicinity.

Nelson - 2

LaSalle occupies approximately 3,875 acres, of which approximately 2,058 acres comprise the cooling pond. The generating facilities at LaSalle are on the southwest portion of the site and include the reactor building and related structures, a switchyard, administration buildings, warehouses, and other structures. The ROW for the cooling water makeup and blowdown pipelines runs for a distance of 3.5 miles north from the cooling pond to the Marseilles Pool portion of the Illinois River. An intake pumphouse and a discharge structure are on the south bank of the Marseilles Pool, approximately 1,000 feet apart.

The ROW for the makeup and blowdown pipelines crosses the eastern portion of the Marseilles State Fish and Wildlife Area, a 2,550-ac area managed by the Illinois Department of Natural Resources (DNR) for hunting and wildlife habitat. Marseilles State Fish and Wildlife Area (including the portion of the pipelines ROW that crosses it) also is used by the Illinois National Guard for training when hunting seasons are closed.

The cooling pond, which provides the LaSalle condenser with a continuous supply of cooling water, was created by constructing dikes that rise above the surrounding land. The cooling pond has an elevation of 700 feet above mean sea level at normal pool capacity. Illinois DNR leases the cooling pond, except the ultimate heat sink portion (83 acres), from Exelon and manages it for public fishing. The cooling pond serves as the water supply for an Illinois DNR fish hatchery located on land adjacent to the pond and also leased to Illinois DNR by Exelon Generation.

Cooling water blowdown from the cooling pond as well as monitored plant effluents are released to the Illinois River via the blowdown pipeline, a plunge pool, and an open, rip-rap-lined channel located downstream of the river intake pumphouse. This discharge is subject to limitations established by National Pollutant Discharge Elimination System (NPDES) Permit IL0048151.

Threatened and Endangered Species in the Project Vicinity

Bald eagles were observed in the LaSalle vicinity during the 1970s, but Exelon is not aware of bald eagle sightings in recent years. Although the USFWS removed the bald eagle from the federal list of threatened and endangered species in 2007, it is still federally protected under the Bald and Golden Eagle Protection Act and the Migratory Bird Treaty Act. Exelon is not aware of any other federally listed aquatic or terrestrial species being observed on the LaSalle site. The only state-listed species that Exelon is aware of being observed or recorded at LaSalle is the peregrine falcon. A pair nested on the roof of the LaSalle auxiliary building several years ago, but no nesting has been observed in recent years. Exelon personnel occasionally observe peregrine falcons flying in the vicinity of LaSalle.

The LaSalle license renewal project information was submitted to the Illinois DNR through the EcoCAT system. Attached for your review are the EcoCAT Natural Resource Review results from a query of the Illinois Natural Heritage database for LaSalle. The attached query response for LaSalle indicates that the Marseilles Illinois Natural Area Inventory (INAI), the LaSalle Lake INAI, and the Marseilles Hill Prairie INAI sites are in the vicinity of LaSalle. No protected species were identified.

Activities during the License Renewal Terms

Renewal of LaSalle operating licenses will not require new construction, land-disturbing activities, changes to plant operations, or modifications of the intake or discharge pipelines. Operation and maintenance activities during the terms of the renewed licenses are expected to occur mostly in previously disturbed areas. In addition, Exelon adheres to regulatory requirements regarding sensitive areas that could contain threatened or endangered species and works closely with USFWS and Illinois DNR to protect these resources. Therefore, Exelon expects that continued operation and maintenance of LaSalle over the license renewal periods (i.e., an additional 20 years for each unit), including maintenance of the ROW for the cooling water makeup and blowdown pipelines, would not adversely affect any ecologically significant habitats or any species that is federally-listed or proposed for listing as threatened or endangered.

Nevertheless, Exelon is requesting your help to identify potential impacts or other issues we may have overlooked that need to be addressed in the LaSalle license renewal environmental report. We are also interested in learning of any information that is not included here and that your staff believes could help expedite the NRC's review of the LaSalle license renewal application. Hence, in closing, we would appreciate receiving a response from you detailing such issues and information for the LaSalle site and cooling water pipeline ROW. We would also welcome your confirmation of our conclusion that LaSalle license renewal activities would not adversely affect ecologically significant habitats or any species that is federally-listed or proposed for listing as threatened and endangered.

Because Exelon will incorporate a copy of your response, as well as this letter, into the LaSalle license renewal environmental report that will be submitted to the NRC as part of the LaSalle license renewal application, your response will be most helpful if it is received by April 30, 2014.

Please refer any questions regarding this submittal to Nancy Ranek, our License Renewal Environmental Lead, at (610) 765-5369. Thank you in advance for your assistance.

Sincerely,

Michael P. Gallagher

Michael P. Gallagher

Enclosures:

Figure 1: Project Location Map
EcoCAT Natural Resources Review results for LaSalle Station

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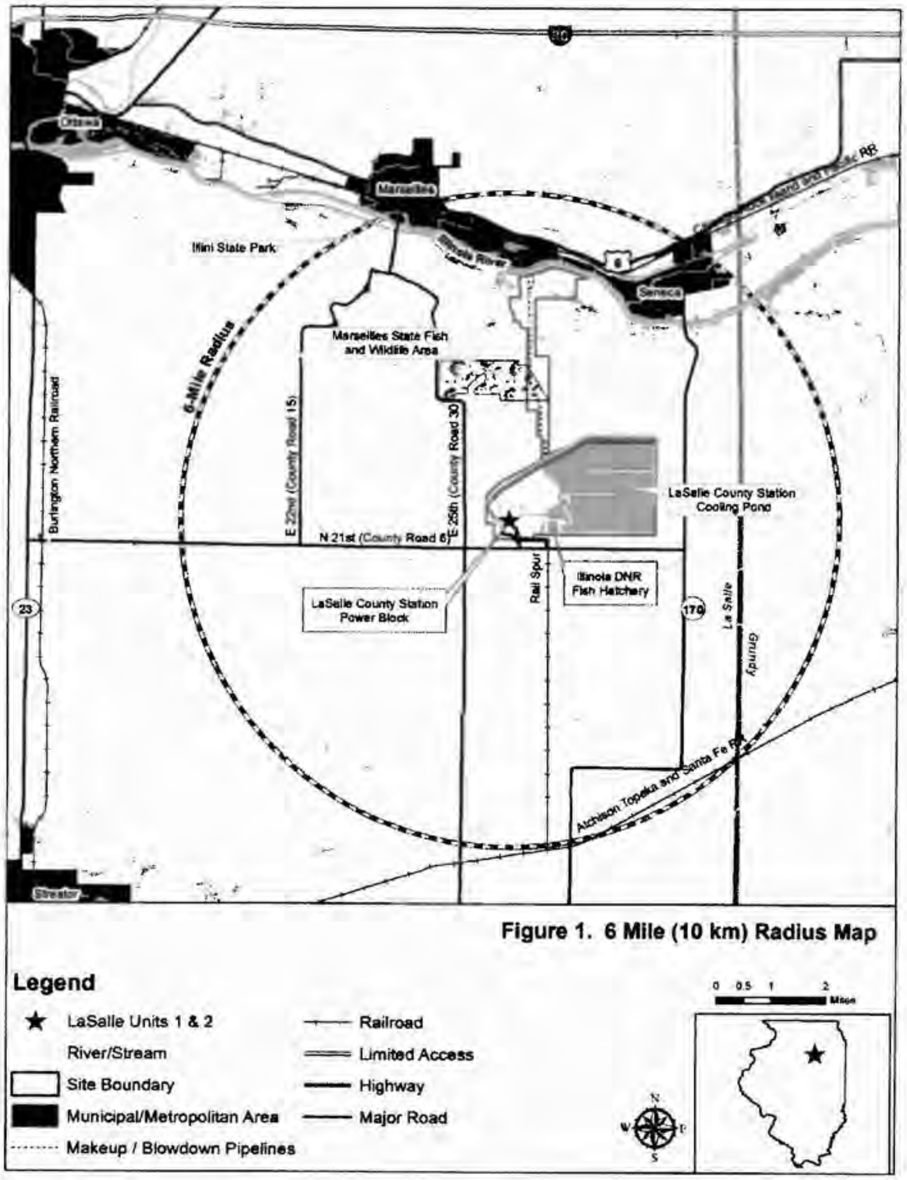

Figure 1. 6 Mile (10 km) Radius Map

Nelson - 5

EcoCAT
Ecological Compliance Assessment Tool

Applicant: Exelon Generation Company LLC
Contact: Nancy L. Ranek
Address: 200 Exelon Way
Kennett Square, PA 19348

IDNR Project Number: 1404780
Date: 09/24/2013

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for LaSalle Generating Station, Units 1 and 2
2601 North 21st Road, Marseilles

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for LaSalle Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes at the Station.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database shows the following protected resources may be in the vicinity of the project location:

Illinois River - Marseilles INAI Site
Lasalle Lake INAI Site
Marseilles Hill Prairie INAI Site

Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: LaSalle

Township, Range, Section
32N, 5E, 4
32N, 5E, 5
32N, 5E, 8
32N, 5E, 9
32N, 5E, 10
32N, 5E, 11
32N, 5E, 14
32N, 5E, 15
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33N, 5E, 21
33N, 5E, 22
33N, 5E, 28
33N, 5E, 29
33N, 5E, 32
33N, 5E, 33

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IDNR Project Number: 1404780

IL Department of Natural Resources Contact
Impact Assessment Section
217-785-5500
Division of Ecosystems & Environment

Disclaimer

The Illinois Natural Heritage Database cannot provide a conclusive statement on the presence, absence, or condition of natural resources in Illinois. This review reflects the information existing in the Database at the time of this inquiry, and should not be regarded as a final statement on the site being considered, nor should it be a substitute for detailed site surveys or field surveys required for environmental assessments. If additional protected resources are encountered during the project's implementation, compliance with applicable statutes and regulations is required.

Terms of Use

By using this website, you acknowledge that you have read and agree to these terms. These terms may be revised by IDNR as necessary. If you continue to use the EcoCAT application after we post changes to these terms, it will mean that you accept such changes. If at any time you do not accept the Terms of Use, you may not continue to use the website.

1. The IDNR EcoCAT website was developed so that units of local government, state agencies and the public could request information or begin natural resource consultations on-line for the Illinois Endangered Species Protection Act, Illinois Natural Areas Preservation Act, and Illinois Interagency Wetland Policy Act. EcoCAT uses databases, Geographic Information System mapping, and a set of programmed decision rules to determine if proposed actions are in the vicinity of protected natural resources. By indicating your agreement to the Terms of Use for this application, you warrant that you will not use this web site for any other purpose.

2. Unauthorized attempts to upload, download, or change information on this website are strictly prohibited and may be punishable under the Computer Fraud and Abuse Act of 1986 and/or the National Information Infrastructure Protection Act.

3. IDNR reserves the right to enhance, modify, alter, or suspend the website at any time without notice, or to terminate or restrict access.

Security

EcoCAT operates on a state of Illinois computer system. We may use software to monitor traffic and to identify unauthorized attempts to upload, download, or change information, to cause harm or otherwise to damage this site. Unauthorized attempts to upload, download, or change information on this server is strictly prohibited by law.

Unauthorized use, tampering with or modification of this system, including supporting hardware or software, may subject the violator to criminal and civil penalties. In the event of unauthorized intrusion, all relevant information regarding possible violation of law may be provided to law enforcement officials.

Privacy

EcoCAT generates a public record subject to disclosure under the Freedom of Information Act. Otherwise, IDNR uses the information submitted to EcoCAT solely for internal tracking purposes.

Ranek, Nancy L.:(GenCo-Nuc)

Subject: FW: Request for Information on Listed Species and Sensitive Habitats -- LaSalle County

From: Duyvejonck, Jon [mailto:jon_duyvejonck@fws.gov]
Sent: Monday, August 11, 2014 9:59 AM
To: Ranek, Nancy L.:(GenCo-Nuc)
Cc: Fulvio, Albert A:(GenCo-Nuc); Hufnagel Jr, John G:(GenCo-Nuc)
Subject: Re: Request for Information on Listed Species and Sensitive Habitats -- LaSalle County

Nancy,
I have reviewed the information you provided regarding federally listed species and the potential effect of license renewal at the LaSalle Generating Station. I concur with your conclusion that the license renewal will not affect any federally listed species. Thank you.

Jon Duyvejonck
US Fish and Wildlife Service
1511 - 47th ave
Moline, IL 61265
tel. 309/757-5800, ex 207

****

On Wed, Aug 6, 2014 at 9:05 AM, Ranek, Nancy L.:(GenCo-Nuc) <Nancy.Ranek@exeloncorp.com> wrote:

Hi Jon –
Exelon Generation has reviewed information about the Northern Long eared bat, as you suggested in your email message (below) dated July 2, 2014.

I am attaching a biological evaluation covering all species potentially present at the LaSalle County Station (LSCS) that are federally listed or proposed for federal listing as threatened or endangered.
Hopefully, this document will provide the information you need about all species, including the Northern Long-eared Bat, to be able to concur with the conclusion in Exelon Generation's letter to USFWS dated March 7, 2014 concerning impacts from renewal by the NRC of the LSCS Operating License.

Thank you for your assistance in this matter.

Sincerely,
Nancy

Nancy L. Ranek
License Renewal Environmental Lead
Exelon Generation, LLC
200 Exelon Way, KSA/2-E
Kennett Square, PA 19348
Phone: 610-765-5369

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Fax: 610-765-5658
Email: nancy.ranek@exeloncorp.com

****

From: Duyvejonck, Jon [mailto:jon_duyvejonck@fws.gov]

Sent: Wednesday, July 02, 2014 9:34 AM
To: Ranek, Nancy L.:(GenCo-Nuc)
Subject: Re: Request for Information on Listed Species and Sensitive Habitats -- LaSalle County

Nancy,

I reviewed your letter concerning the re-licensing of the LaSalle Nuclear Plant. There has been one recent addition to the federally listed species known to occur in the plant vicinity. That is the Northern Long eared bat. It is not officially listed yet, only proposed. However, it should be considered as listed in your review. That way ,if and when it is listed, you will not have to re-do any consultation. You may wish to visit our web site: http://www.fws.gov/midwest/endangered/section7/index.html to learn more about the Northern Long eared bat. Its habitat is similar enough to the Indiana bat that you can more or less do an assessment for both at the same time.

After all that, we can concur with your letter of March 7, 2014 that the relicensing of the operating permit for the La Salle Plant will not adversely affect any federally listed species. Any further questions, please contact me.

Jon Duyvejonck
US Fish and Wildlife Service
1511 - 47th ave
Moline, IL 61265
tel. 309/757-5800, ex 207

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Exelon Generation.

Michael P. Gallagher
Vice President, License Renewal
Exelon Nuclear

200 Exelon Way
Kennett Square, PA 19348

610 765 5958 Office
610 765 5956 Fax
www.exeloncorp.com

michaelp.gallagher@exeloncorp.com

March 7, 2014

Mr. Todd Rettig
Division Manager
Office of Realty and Environmental Planning
Illinois Department of Natural Resources
1 Natural Resources Way, 2" Floor
Springfield, Illinois 62702-1271

SUBJECT: Exelon Generation Company, LLC – LaSalle County Station Units 1 and 2 License Renewal Project. Request for Information on Listed Species and Sensitive Habitats – LaSalle County

Dear Mr. Rettig:

Exelon Generation Company, LLC (Exelon) plans to apply to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for LaSalle County Station (LaSalle) Units 1 and 2 no later than January 2015. The existing operating license for Unit 1 will expire on April 17, 2022, and the existing operating license for Unit 2 will expire on December 16, 2023. Renewed licenses would allow LaSalle Units 1 and 2 to operate until 2042 and 2043, respectively.

As part of the license renewal process, the NRC requires (10 CFR 51.53(c)(3)(ii)(E)) that the LaSalle license renewal application include an environmental report assessing the impacts from license renewal activities on species listed or proposed for listing as threatened or endangered in accordance with the Endangered Species Act (ESA) (16 USC 1531, et seq.) and on important plant and animal habitats, including critical habitats as defined by the ESA and essential fish habitat as identified under the Magnuson-Stevens Fishery Conservation and Management Act (16 USC 1801. et seq.). Because no species with essential fish habitat is found in Illinois, this letter seeks input from the Illinois Department of Natural Resources (DNR) regarding effects on species and habitats protected under the ESA only that are in the vicinity of LaSalle, including along the right-of-way (ROW) for the cooling water makeup and blowdown pipelines between the LaSalle cooling pond and the Illinois River.

In June 2013, the NRC revised its regulations at 10 CFR Part 51 such that no transmission line ROW associated with LaSalle requires assessment for environmental impacts from license renewal activities.

Project Features

LaSalle is located in northeastern Illinois, about 75 miles southwest of Chicago, in LaSalle County. The property is approximately 6 miles southwest of Seneca and 7 miles south-southeast of Marseilles, as shown in the attached Figure 1. The area surrounding LaSalle is relatively flat, and is rural and agricultural. Numerous wind turbines operate in the immediate vicinity.

Rettig - 2

LaSalle occupies approximately 3,875 acres, of which approximately 2,058 acres comprise the cooling pond. The generating facilities at LaSalle are on the southwest portion of the site and include the reactor building and related structures, a switchyard, administration buildings, warehouses, and other structures. The ROW for the cooling water makeup and blowdown pipelines runs for a distance of 3.5 miles north from the cooling pond to the Marseilles Pool portion of the Illinois River. An intake pumphouse and a discharge structure are on the south bank of the Marseilles Pool, approximately 1,000 feet apart.

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Threatened and Endangered Species in the Project Vicinity

Bald eagles were observed in the LaSalle vicinity during the 1970s, but Exelon is not aware of bald eagle sightings in recent years. Although the USFWS removed the bald eagle from the federal list of threatened and endangered species in 2007, it is still federally protected under the Bald and Golden Eagle Protection Act and the Migratory Bird Treaty Act. Exelon is not aware of any other federally listed aquatic or terrestrial species being observed on the LaSalle site. The only state-listed species that Exelon is aware of being observed or recorded at LaSalle is the peregrine falcon. A pair nested on the roof of the LaSalle auxiliary building several years ago, but no nesting has been observed in recent years. Exelon personnel occasionally observe peregrine falcons flying in the vicinity of LaSalle.

The LaSalle license renewal project information was submitted to the Illinois DNR through the EcoCAT system. Attached for your review are the EcoCAT Natural Resource Review results from a query of the Illinois Natural Heritage database for LaSalle. The attached query response for LaSalle indicates that the Marseilles Illinois Natural Area Inventory (INAI), the LaSalle Lake INAI, and the Marseilles Hill Prairie INAI sites are in the vicinity of LaSalle. No protected species were identified.

Activities during the License Renewal Terms

Renewal of LaSalle operating licenses will not require new construction, land-disturbing activities, changes to plant operations, or modifications of the intake or discharge pipelines.

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Operation and maintenance activities during the terms of the renewed licenses are expected to occur mostly in previously disturbed areas. In addition, Exelon adheres to regulatory requirements regarding sensitive areas that could contain threatened or endangered species and works closely with USFWS and Illinois DNR to protect these resources. Therefore, Exelon expects that continued operation and maintenance of LaSalle over the license renewal periods (i.e., an additional 20 years for each unit), including maintenance of the ROW for the cooling water makeup and blowdown pipelines, would not adversely affect any ecologically significant habitats or any species that is federally-listed or proposed for listing as threatened or endangered.

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Because Exelon will incorporate a copy of your response, as well as this letter, into the LaSalle license renewal environmental report that will be submitted to the NRC as part of the LaSalle license renewal application, your response will be most helpful if it is received by April 30, 2014.

Please refer any questions regarding this submittal to Nancy Ranek, our License Renewal Environmental Lead, at (610) 765-5369. Thank you in advance for your assistance.

Sincerely,

Michael P. Gallagher

Michael P. Gallagher

Enclosures:

Figure 1: Project Location Map
EcoCAT Natural Resources Review results for LaSalle Station

Rettig - 4

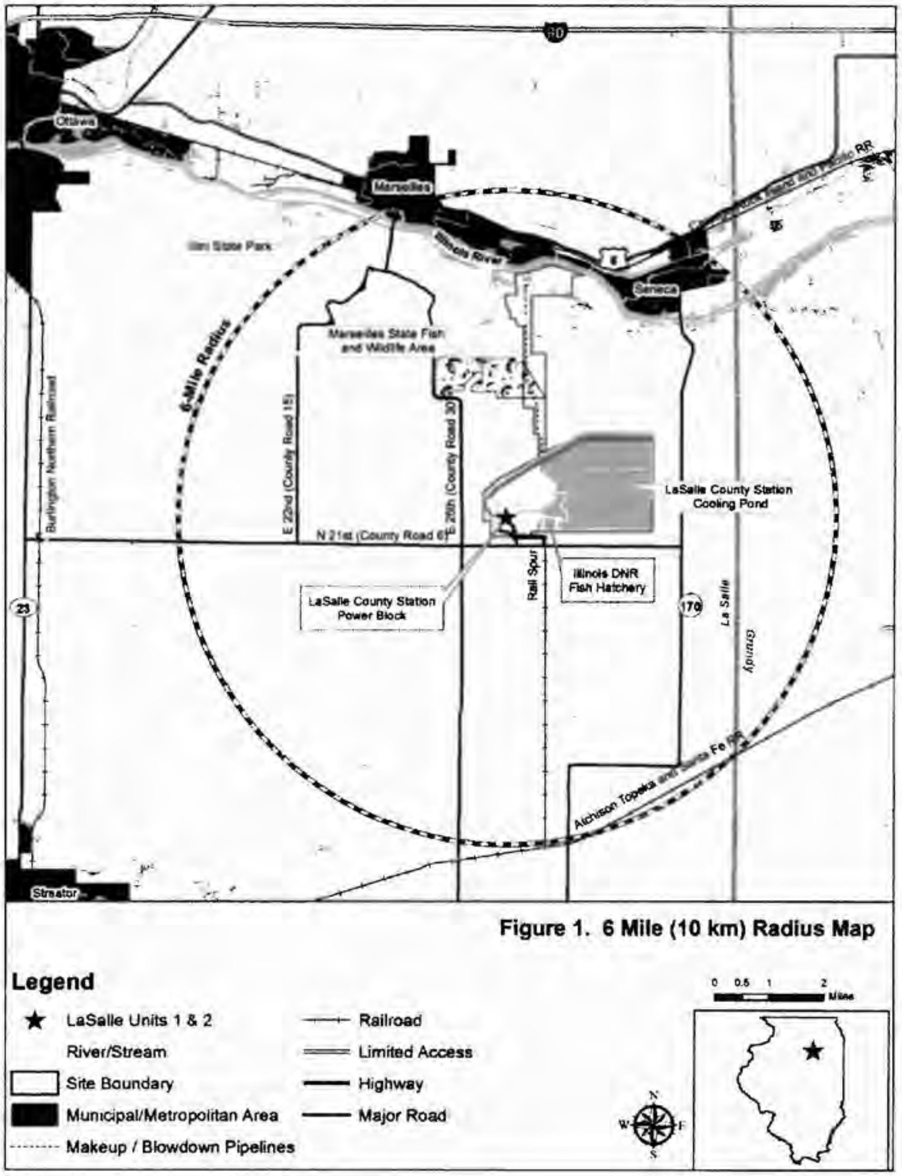

Figure 1. 6 Mile (10 km) Radius Map

Rettig - 5

EcoCAT
Ecological Compliance Assessment Tool

Applicant:	Exelon Generation Company LLC	*IDNR Project Number:*	1404780
Contact:	Nancy L. Ranek	*Date:*	09/24/2013
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for LaSalle Generating Station, Units 1 and 2
2601 North 21st Road, Marseilles

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for LaSalle Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes at the Station.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database shows the following protected resources may be in the vicinity of the project location:

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Lasalle Lake INAI Site
Marseilles Hill Prairie INAI Site

Location
The applicant is responsible for the accuracy of the location submitted for the project.

County: LaSalle

Township, Range, Section:
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32N, 5E, 14
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33N, 5E, 29
33N, 5E, 32
33N, 5E, 33

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IDNR Project Number: 1404780

IL Department of Natural Resources Contact
Impact Assessment Section
217-785-5500
Division of Ecosystems & Environment

Disclaimer

The Illinois Natural Heritage Database cannot provide a conclusive statement on the presence, absence, or condition of natural resources in Illinois. This review reflects the information existing in the Database at the time of this inquiry, and should not be regarded as a final statement on the site being considered, nor should it be a substitute for detailed site surveys or field surveys required for environmental assessments. If additional protected resources are encountered during the project's implementation, compliance with applicable statutes and regulations is required.

Terms of Use

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Illinois Department of
Natural Resources
One Natural Resources Way Springfield, Illinois 62702-1271
http://dnr.state.il.us

Pat Quinn, Governor
Marc Miller, Director

May 22, 2014

MPG 6.3.14

Mr. Michael P. Gallagher
Vice President, License Renewal
Exelon Nuclear
200 Exelon Way
Kennett Square, PA 19348

Re: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission (NRC) for LaSalle Generating Station, Units 1 and 2 - Correspondence dated March 7, 2014
County: LaSalle

Dear Mr. Gallagher:

This letter is in reference to your request for information on listed threatened and endangered species relative to your license renewal correspondence dated March 7, 2014.

The Department has records of several state-listed species that were observed just downstream of your discharge point on the Illinois River. These include the state-endangered Blacknose Shiner (*Notropis heterolepis)* and Greater Redhorse (*Moxostoma valenciennesi*), and the state-threatened River Redhorse (*Moxostoma carinatum*) and Banded Killifish (*Fundulus diaphanous*). These species were all observed within the Illinois River – Marseilles INAI site, which extends approximately seven miles upstream and downstream of your discharge structure and intake pumphouse.

Since you have indicated there will be no new construction, land-disturbing activities, changes to plant operations, or modifications of the intake or discharge piplelines, no further comment by the Department is necessary at this time.

Thank you for the opportunity to provide this clarification. Please contact me if you need additional information.

Cordially,

Sheldon R. Fairfield

Sheldon R. Fairfield
Impact Assessment Section
Division of Ecosystems & Environment
Phone: (217) 782-0031
Sheldon.Fairfield@illinois.gov

Appendix E

Cultural Resources Correspondence

LaSalle County Station Environmental Report

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Exelon Generation

March 7, 2014

Ms. Anne E. Haaker
Deputy State Historic Preservation Officer
Preservation Services Division
Illinois Historic Preservation Agency
1 Old State Capitol Plaza
Springfield, Illinois 62701-1507

Subject: Exelon Generation Company, LLC – LaSalle County Station Units 1 and 2 License Renewal Application. Request for Information on Historic and Archaeological Resources

Dear Ms. Haaker:

Exelon Generation Company, LLC (Exelon) plans to apply to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for LaSalle County Station (LaSalle) Units 1 and 2, no later than January 2015. The existing operating license for Unit 1 expires on April 17, 2022, and the existing operating license for Unit 2 expires on December 16, 2023. Renewed licenses would allow LaSalle Units 1 and 2 to operate until 2042 and 2043, respectively.

As part of the license renewal process, the NRC requires that the LaSalle license renewal application include an environmental report assessing the impacts from license renewal activities on historic and cultural resources on or near the LaSalle site. Pursuant to the National Environmental Policy Act (NEPA), this letter seeks input from the Illinois SHPO regarding such effects in the vicinity of LaSalle, including along the right-of-way (ROW) for the cooling water makeup and blowdown pipelines between the LaSalle cooling pond and the Illinois River. Later, the NRC may also request an informal consultation with your office in accordance with Section 106 of the National Historic Preservation Act of 1966, as amended (16 USC 470), and the federal Advisory Council on Historic Preservation regulations (36 CFR 800).

In June 2013, the NRC revised its regulations at 10 CFR Part 51 such that no transmission line ROW associated with LaSalle requires assessment for environmental impacts from license renewal activities.

Project Features

LaSalle is located in northeastern Illinois, approximately 75 miles southwest of Chicago, in LaSalle County. The property is approximately 6 miles southwest of Seneca and 7 miles south-southeast of Marseilles, as shown in the attached Figure 1. The area surrounding LaSalle is relatively flat, and is rural and agricultural. Numerous wind turbines operate in the immediate vicinity.

LaSalle occupies approximately 3,875 acres, of which approximately 2,058 acres comprise the cooling pond. The generating facilities at LaSalle are on the southwest portion of the site and include the reactor building and related structures, a switchyard, administration buildings, warehouses, and other structures. The ROW for the cooling water makeup and blowdown pipelines runs for a distance of 3.5 miles north from the cooling pond to the Marseilles Pool portion of the Illinois River. An intake pumphouse and a discharge structure are on the south bank of the Marseilles Pool, approximately 1,000 feet apart.

The ROW for the makeup and blowdown pipelines crosses the eastern portion of the Marseilles State Fish and Wildlife Area, a 2,550-ac area managed by the Illinois Department of Natural Resources (DNR) for hunting and wildlife habitat. Marseilles State Fish and Wildlife Area (including the portion of the pipelines ROW that crosses it) also is used by the Illinois National Guard for training when hunting seasons are closed.

The cooling pond, which provides the LaSalle condenser with a continuous supply of cooling water, was created by constructing dikes that rise above the surrounding land. The cooling pond has an elevation of 700 feet above mean sea level at normal pool capacity. Illinois DNR leases the cooling pond, except the ultimate heat sink portion (83 acres), from Exelon and manages it for public fishing. The cooling pond serves as the water supply for an Illinois DNR fish hatchery located on land adjacent to the pond and also leased to Illinois DNR by Exelon Generation.

Identification of Historic and Archaeological Resources

The land occupied by LaSalle was previously used primarily for agriculture. Settlement was slow to begin along the southern side of the Illinois River Valley, and the oldest historic sites are on or near the prairie forest ecotone and near either upland closed depressions, or valley springs. Historic farmsteads in the area replicate a trend noted throughout the Prairie Peninsula—early settlers tended to settle along the ecotone to obtain wood for fuel and building materials, to use the prairie as open range for cattle, and to plow the more easily tillable forest soils after the advent of the steel-tipped plow. In comparison, while historic sites are predominantly in the level uplands, prehistoric sites are found in near-riverine settings.

The National Register Information System (NRIS) on-line database was accessed during 2012 to identify historic properties listed on the NRHP within a 6-mile radius of LaSalle. Seven listed properties were identified and are summarized in Table 1.

Table 1. Sites listed on National Register of Historic Places within 6 miles of LaSalle

Site Name/Number	Address	City, County
Sacred Heart Church (NR165052)	221 W. Emmet St.	Kinsman, Grundy
Hay Barn (NR165106)	2319 N. 14th Rd.	Streator, LaSalle
Ransom Water Tower (NR200859)	Plumb St.	Marseilles, LaSalle
Marseilles Hydro Plant (NR200999)	Commercial St.	Marseilles, LaSalle
Armour's Warehouse (NR201063)	William & Bridge Sts.	Seneca, LaSalle
Rock Island & Pacific Railroad Depot (NR201098)	151 Washington St.	Marseilles, LaSalle
Illinois & Michigan Canal (NR200462)	U.S. 6 in Channahon State Park	Lockport to LaSalle-Peru; Will, Grundy, LaSalle

In 1972, prior to construction at LaSalle, the Illinois Archaeological Survey (IAS) completed a Phase I Archaeological Survey of the LaSalle site (originally proposed as the Collins Generating Station) and concluded that the facility would have no significant impact on archaeological resources. Locations LS00207, LS00208, and LS00209 were three of five isolated finds identified in the 1972 survey. At the time of the Phase I survey, IAS did not recognize isolated finds as sites, and the isolated finds were not recorded or assigned IAS accession numbers. Because isolated finds LS00207, LS00208, and LS00209, by definition, were not eligible for inclusion on the NRHP, they were not evaluated. The NRC's Final Environmental Statement relating to the operation of LaSalle, which was published in November 1978 (NUREG-0486), stated that "[t]here are no historical and cultural sites recorded in the National Registry of National Landmarks, as supplemented 8 June 1976, or the National Register of Historic Places, as supplemented 3 January 1978, located on the LaSalle County Station site."

The results of an Illinois State Archaeological Site Files review conducted in 2012 indicated that 146 previously-recorded archaeological sites are located within 6 miles of LaSalle. Six sites are on the LaSalle property; three of the six are the previously discussed isolated finds identified in the 1972 survey. The remaining three sites (LS00252, LS00514, LS00533) were identified in reports of archaeological surveys conducted during 1974-1975 for LaSalle's transmission and pipeline corridors or during 1983 and 1993-1994 for the Marseilles Training Area. No additional archaeological resources have been recorded on the LaSalle property since 1995. Table 2 provides an overview of the known archaeological resources on the LaSalle property.

Table 2. Archaeological Sites located within the LaSalle Property

Site Number/Name	Site Type	NRHP Eligibility
LS00207/ Collins Station Site #1	Unknown Prehistoric	Isolated, Not Eligible
LS00208/ Collins Station Site #2	Unknown Prehistoric	Isolated, Not Eligible
LS00209/ Collins Station Site #3	Unknown Prehistoric	Isolated, Not Eligible
LS00252	Unknown Prehistoric	Not Eligible
LS00514/ Boog Powell	Unknown Prehistoric	Not Eligible
LS00533	Unknown Prehistoric	Not Eligible

Activities during the License Renewal Term

Renewal of LaSalle operating licenses will not require new construction, land-disturbing activities, changes to plant operations, or modifications of the intake or discharge pipelines. Operation and maintenance activities during the terms of the renewed licenses are expected to occur mostly in previously disturbed areas. Therefore, Exelon expects that continued operation and maintenance of LaSalle over the license renewal periods (i.e., an additional 20 years for each unit), including maintenance of the ROW for the cooling water makeup and blowdown pipelines, would not adversely affect any archaeological or historically significant resources. Even so, Exelon has implemented specific procedures to protect cultural resources in undisturbed areas from activities related to operation and maintenance on the LaSalle site, including along the ROW for the makeup and blowdown pipelines. Potential effects on cultural resources from future activities would be identified in advance and avoided, if a practical alternative to the proposed activity can be identified. If avoidance is not practical, then the Illinois SHPO would be consulted regarding mitigation.

As stated earlier, this letter seeks input from the Illinois SHPO regarding the effects that license renewal activities may have on historic and archaeologically significant resources in the vicinity of LaSalle. After your review of the information provided in this letter, Exelon would appreciate your sending a letter detailing any concerns you may have about historic and archaeological resources within 2 miles of LaSalle or the ROW for the makeup and blowdown pipelines, or confirming that the operation of LaSalle over the license renewal terms would have no effect on known historic or archaeological resources.

Because Exelon will incorporate a copy of your response, as well as this letter, into the LaSalle license renewal environmental report that will be submitted to the NRC as part of the LaSalle license renewal application, your response would be most helpful if it is received by April 30, 2014.

Please refer any questions regarding this submittal to Nancy Ranek, our License Renewal Environmental Lead at (610) 765-5369. Thank you in advance for your assistance.

Sincerely,

Michael P. Gallagher

Michael P. Gallagher

Enclosures:

Figure 1: Project Location Map

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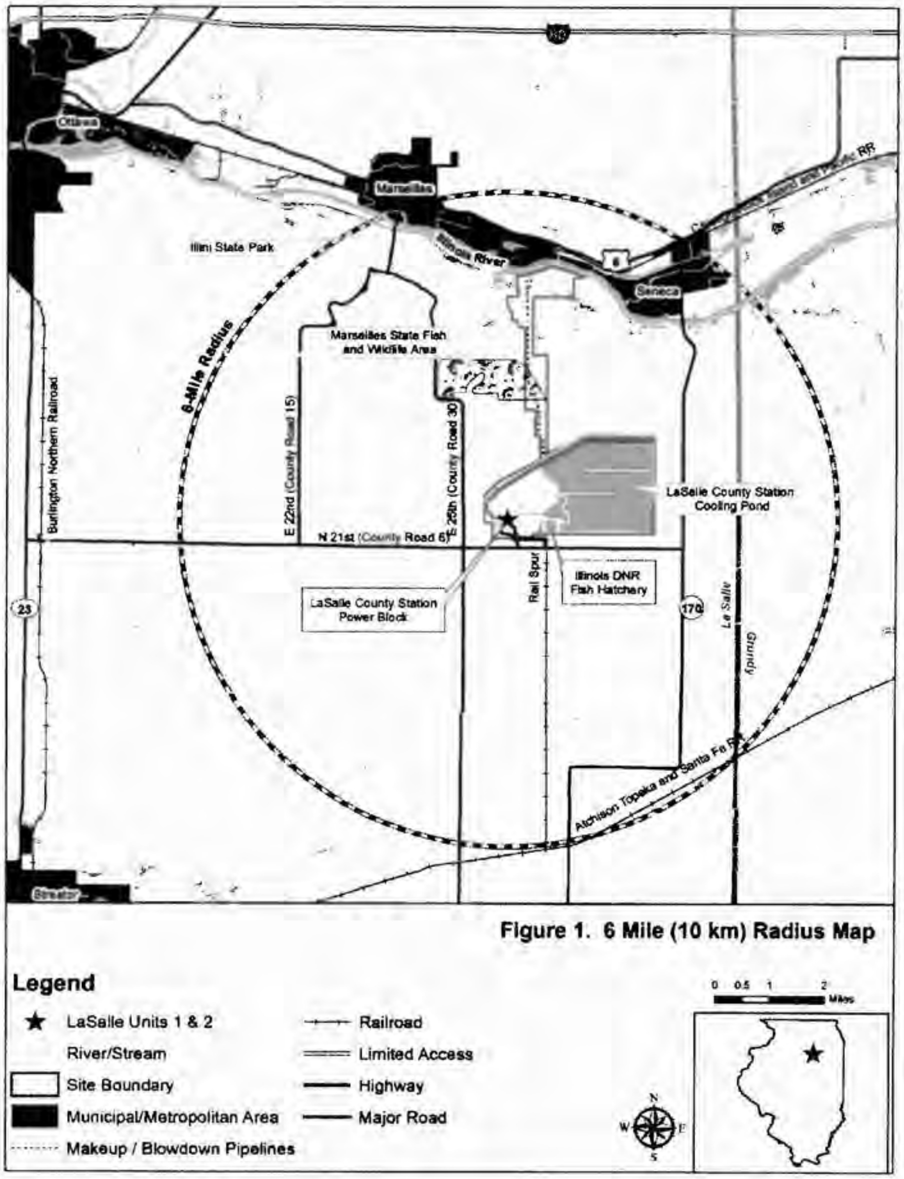

Figure 1. 6 Mile (10 km) Radius Map

Illinois Historic Preservation Agency

1 Old State Capitol Plaza, Springfield, IL 62701-1512

FAX (217) 524-7525
www.illinoishistory.gov

received 3/31/2014

LaSalle County
Marseilles
Renewal of Operating Licenses for LaSalle County Station Units 1 and 2
2601 N. 21st Rd.
IHPA Log #016031314

March 27, 2014

Nancy Ranek
Exelon Generation Company, LLC
200 Exelon Way
Kennett Square, PA 19348

Dear Ms. Ranek:

We have reviewed the documentation submitted for the referenced project in accordance with 36 CFR Part 800.4. Based upon the information provided, no historic properties are affected. We, therefore, have no objection to the undertaking proceeding as planned.

Please retain this letter in your files as evidence of compliance with section 106 of the National Historic Preservation Act of 1966, as amended. This clearance remains in effect for two years from date of issuance. It does not pertain to any discovery during construction, nor is it a clearance for purposes of the Illinois Human Skeletal Remains Protection Act (20 ILCS 3440).

If you have any further questions, please contact me at 217/785-5027.

Sincerely,

Anne E. Haaker

Anne E. Haaker
Deputy State Historic
Preservation Officer

For TTY communication, dial 888-440-9009. It is not a voice or fax line.

Appendix F

Severe Accident Mitigation Alternatives Analysis

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Acronyms

ADS	Automatic Depressurization System
ATD	Atmospheric Transport and Dispersion
ATWS	Anticipated Transient Without Scram
BOC	Break Outside Containment
BOP	Balance of Plant
BWR	Boiling Water Reactor
CCF	Common Cause Failure
CDF	Core Damage Frequency
CET	Containment Event Tree
CRD	Control Rod Drive
CSCS	Core Standby Cooling System
CST	Condensate Storage Tank
DFP	Diesel Fire Pump
DG	Diesel Generator
DGCW	Diesel Generator Cooling Water
DW	Drywell
EALs	Emergency Action Levels
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EGC	Exelon Generation Company
EOPs	Emergency Operating Procedures
EPZ	Emergency Planning Zone
ESW	Emergency Service Water
ETE	Evacuation Time Estimate
F&Os	Facts and Observations
FASA	Focused Area Self-Assessment
FP	Fire Protection
FPS	Fire Protection System
F-V	Fussell - Vesely
FW	Feedwater
GE	General Emergency
HCTL	Heat Capacity Temperature Limit

Acronyms	
HEAF	High Energy Arcing Fault
HEP	Human Error Probability
HFE	Human Failure Event
HPCS	High Pressure Core Spray
HRA	Human Reliability Analysis
HVAC	Heating Ventilating Air Conditioning
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination – External Events
ISLOCA	Interfacing Systems Loss of Coolant Accident
JHEP	Joint Human Error Probability
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
LOIA	Loss of Instrument Air
LOOP	Loss of Offsite Power
LP	Low Pressure
LPCI	Low Pressure Coolant Injection
LPCS	Low Pressure Core Spray
LSCS	LaSalle County Station
MAAP	Modular Accident Analysis Program
MACCS2	MELCOR Accident Consequences Code System, Version 2
MACR	Maximum Averted Cost-Risk
MCC	Motor Control Center
MSIV	Main Steam Isolation Valve
NDE	Nondestructive Evaluation
NPSH	Net Positive Suction Head
NRC	U.S. Nuclear Regulatory Commission
OECR	Off-site economic cost risk
OSP	Off Site Power
PRA	Probabilistic Risk Assessment
PSA	Probabilistic Safety Assessment
PSF	Performance Shaping Factor
RAW	Risk Achievement Worth

Acronyms	
RCIC	Reactor Core Isolation Cooling
RDR	Real Discount Rate
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RMIEP	Risk Methods Integration & Evaluation Program
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RRW	Risk Reduction Worth
RWCU	Reactor Water Cleanup
SACs	Station Air Compressions
SAG	Severe Accident Guidelines
SAMA	Severe Accident Mitigation Alternative
SAT	System Auxiliary Transformer
SBLC	Standby Liquid Control
SBO	Station Blackout
SORV	Stuck Open Relief Valve
SP	Suppression Pool
SPC	Suppression Pool Cooling
SRV	Safety Relief Valve
SSES	Susquehanna Steam Electric Station
SW or WS	Service Water
T&RM	Training and Reference Material (Exelon Generation Company guidance document one tier lower than a procedure)
TDRFP	Turbine Driven Reactor Feedwater Pump
URE	Updating Requirement Evaluation

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SEVERE ACCIDENT MITIGATION ALTERNATIVES

The severe accident mitigation alternatives (SAMA) analysis summarized in Section 4.15 of this Environmental Report is presented below.

F.1 METHODOLOGY

The methodology selected for this analysis is contained in NEI 05-01, Rev. A, Severe Accident Mitigation Alternatives (SAMA) Analysis Guidance Document (NEI 2005), which has been reviewed and endorsed by the U.S. Nuclear Regulatory Commission (NRC). It involves identifying SAMA candidates that have the potential to reduce plant risk (frequency and/or consequences of a severe accident) and evaluating whether or not the implementation of those candidates is potentially beneficial on a cost-risk reduction basis. The metrics chosen to represent plant risk include the core damage frequency (CDF), the dose-risk, and the offsite economic cost-risk. Those metrics provide a measure of both the likelihood and consequences of a core damage event.

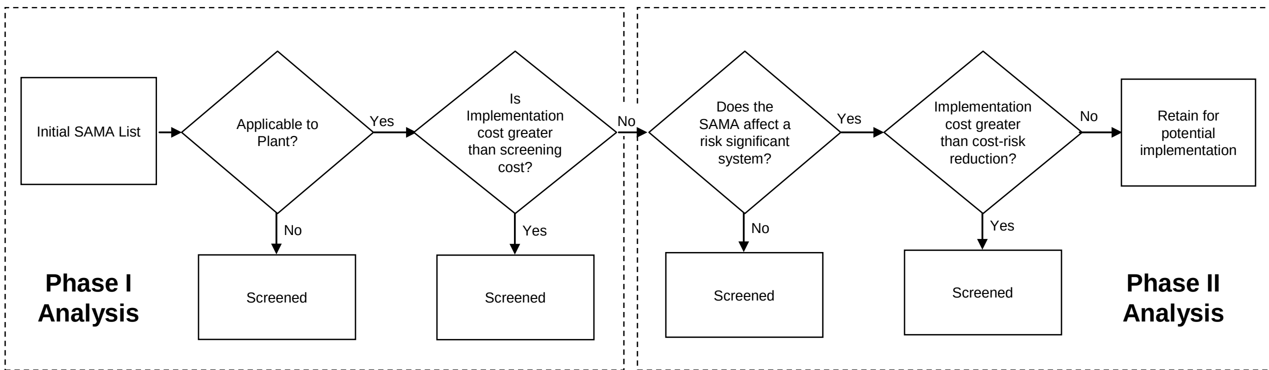
The SAMA process consists of the following principal steps:

- LaSalle County Station (LSCS) Probabilistic Risk Assessment (PRA) Model – Use the LSCS Internal Events PRA model as the basis for the analysis (Section F.2). Incorporate External Events contributions as described in Section F.4.6.2.
- Level 3 PRA Analysis – Use the LSCS Level 1 and 2 Internal Events PRA output and site-specific meteorology, demographic, land use, and emergency response data as inputs to a Level 3 PRA performed using the MELCOR Accident Consequences Code System Version 2 (MACCS2) (Section F.3). Incorporate External Events contributions as described in Section F.4.6.2.
- Baseline Risk Monetization – Use NRC regulatory analysis techniques (NRC 1997) to calculate the monetary value of the LSCS severe accident risk. That value represents the maximum averted cost-risk (MACR) (Section F.4).
- Phase 1 SAMA Analysis – Identify potential SAMA candidates based on the LSCS Probabilistic Risk Assessment (PRA), Individual Plant Examination (IPE), Individual Plant Examination – External Events (IPEEE), and other relevant industry and NRC documentation. Screen out SAMA candidates that are not applicable to the LSCS plant design or are of low benefit in boiling water reactors (BWRs) such as LSCS; candidates that have already been implemented at LSCS or whose benefits have been achieved at LSCS using other means; and candidates whose estimated cost exceeds the maximum possible averted cost-risk (Section F.5).
- Phase 2 SAMA Analysis – Calculate the risk reduction attributable to each of the remaining SAMA candidates and compare it to the estimated cost of implementation to identify the net cost-benefit. PRA insights are also used to screen SAMA candidates in this phase (Section

F.6). For example, SAMAs that only impact interfacing system loss of coolant accidents (ISLOCAs) may be screened if the SAMA's cost of implementation exceeds the cost-risk associated with ISLOCA scenarios.

- Sensitivity Analysis – Evaluate how changes in the SAMA analysis assumptions might affect the cost-benefit evaluation (Section F.7).
- Conclusions – Summarize results and identify conclusions (Section F.8).

The steps outlined above are described in more detail in the subsections of this appendix. The graphic below provides a high level overview of the SAMA analysis screening process.



SAMA SCREENING PROCESS

F.2 LSCS PRA MODEL

The purpose of this section is to summarize the key aspects of the LSCS PRA model, including its development, quantitative results, and insights from the LSCS PRA 2013 update. The LSCS PRA model (LS213A), which was used to support the SAMA analysis, quantifies the core damage frequency (CDF) and a full range of Level 2 release categories. The PRA is a Unit 2 model, but because the units are nearly identical, it is considered to be applicable to Unit 1 unless otherwise noted.

The Level 1 PRA quantifies the frequency of severe accidents that may compromise mitigative and preventive engineering safety features and, ultimately, cause damage to the nuclear reactor core. The primary result of a Level 1 PRA is quantification of the CDF based on initiating events analysis, scenario development, system analyses, and human-factor evaluations.

The LSCS Level 1 PRA addresses internal events, including flooding, and loss of off-site power. External events such as fires, seismic, tornadoes and external flooding, which were analyzed separately in response to NRC Generic Letter 88-20, Supplement 4 (NRC 1991) are also addressed separately from the internal events risk in the SAMA analysis (refer to sections F.4.6.2 and F.5.1.6).

The mitigating systems referred to in the Level 1 logic model are those which shut down the reactor, provide core cooling to prevent overheating (or, ultimately, fuel melting), or provide containment heat removal. Any support systems that are necessary for the front-line systems to be successful are also included within the Level 1 scope.

The B.5.b and FLEX equipment[1] are not incorporated into the PRA.

The Level 1 logic model is developed to display and provide a calculational vehicle for the critical safety functions to mitigate these initiating events and to estimate the overall core damage frequency. The basic concept of a Level 1 PRA is simple. However, the large number of initiating events, systems, components, and human interactions associated with nuclear plant operation and maintenance, make the performance of the Level 1 PRA analysis complex.

The LSCS PRA model is updated periodically in accordance with internal Exelon Generation Company (EGC) procedures to reflect plant modifications, procedure changes, and the plant-specific failure data and maintenance unavailability for major plant components

F.2.1 PRA UPDATE FREEZE DATE

The freeze date for data and plant modifications to be considered for the Level 1 portion of the LS213A model (the 2011 LSCS PRA update, LS211A) is December 31, 2010.

The Emergency Operating Procedures (EOPs) and Severe Accident Guidelines (SAGs) used in this analysis are those in place as of the freeze date.

No significant plant modifications affecting the risk profile were performed since the PRA model freeze date. EOP and SAG changes made since the freeze date were reviewed and incorporated, as necessary, into the LS213A model. The freeze date for the LS213A model was December 31, 2013.

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[1] The Diverse and Flexible Coping Strategies (FLEX) are measures intended to reduce the risk associated with beyond design basis external events. The B.5.b program includes the implementation of procedures and equipment designed to reduce plant risk associated with core damage and release caused by a large fire or explosion.

F.2.2 PRA HISTORY

Since the original LSCS Individual Plant Examination (IPE) submittal to the NRC (CeCo 1994), eight LSCS PRA revisions have been performed up to and including this analysis:

1. 1994 IPE
2. 1996 Model
3. 1999 Model Upgrade[2]
4. 2000 Model Upgrade
5. 2001A Model
6. 2003A Model
7. 2006 (A, B, and C) Model
8. 2011A Model
9. 2013A Upgrade

Two of the upgrades (items 3 and 4) shown above were done in stages. The 1999 upgrade included two revisions (0 and 1), while the 2000 upgrade included three revisions (A, B, and C). Table F.2-1 provides a summary of the quantitative results for each of these models.

F.2.2.1 1994 IPE

Sandia National Laboratories, under contract to the NRC, completed a Level 1 and Level 2 PRA for LSCS Unit 2 in 1992. This PRA was documented in the multi-volume *Analysis of the LaSalle Unit 2 Nuclear Power Plant: Risk Methods Integration and Evaluation Program (RMIEP)* (NRC 1992a). A summary of the Sandia PRA was submitted to the NRC in April 1994 as LSCS's response to NRC Generic Letter 88-20, *Individual Plant Examination for Severe Accident Vulnerabilities (IPE)* (NRC 1989).

F.2.2.2 1996 MODEL

The "Updated IPE" (1996) was aimed at resolving NRC questions regarding the 1994 IPE. Major revisions included converting the model to a CAFTA linked fault tree, and incorporating plant procedure changes and modifications.

[2] An upgrade is a model update that involves significant changes to modeling methodology and / or level of detail.

F.2.2.3 1999 MODEL

The purpose of the 1999 LSCS PRA upgrade was to support plant applications. The 1999 model upgrade was documented in two revisions. Revision 0 was issued before System Manager reviews had been completed. Those reviews identified corrections for several logic errors and other potential enhancements that were incorporated into Revision 1. Since the Revision 0 model was not used for any plant applications, the Revision 1 model is referred to as the 1999 model. Major differences between the 1996 model and the 1999 (Revision 1) model are summarized below:

- The 1999 model provides more credit for offsite AC power recovery;
- The 1999 model credits use of the turbine driven reactor feedwater pump (TDRFP) for turbine trip (TT) initiating events, including anticipated transient without scram (ATWS) events.
- The main condenser was credited in the 1999 model. This non-safety-related system is the normal means of achieving hot and cold shutdown following a SCRAM, but it was not included in the IPE model because it was not necessary to meet the intent of Generic Letter 88-20. Modeling this non-safety-related decay heat removal system is important for plant applications because, without it, the PRA model would overestimate the importance of safety-related decay heat removal systems (e.g., suppression pool cooling) and support systems (e.g., core standby cooling system (CSCS));
- Reactor Core Isolation Cooling (RCIC) dependency was corrected for AC power. The 1996 model had a dependency on AC for room cooling, whereas the 1999 model best estimate is that the RCIC system can operate for the four-hour station blackout (SBO) coping time without the need for room cooling. This is important for SBO scenarios where RCIC is a turbine (steam) driven source;
- Containment modeling in the 1999 model was changed to not always assume core damage upon containment failure; the model allowed for potential success paths (which also reduces dependency on Station Air needed for venting);
- The turbine trip initiating event was a much larger contributor due to the contribution of TT-ATWS. The increase in CDF is due to single operator error for “Operator fails to bypass main steam isolation valves (MSIVs) given FW success;”
- The Service Water (SW) system model was more realistic, including success criteria that are seasonally-dependent; and,
- Credit alignment of diesel fire pump (DFP) for injection post-containment challenge

F.2.2.4 2000A MODEL

The fault trees, event trees, and database of the 1999 model were upgraded to the 2000A model to reflect the current plant configuration and expand the scope of the model to include selected internal floods. This upgrading process involved the following significant changes:

- Increased 125 VDC battery life from four to seven hours to extend RCIC operability during station blackout;
- Included dependency for room cooling for high pressure core spray (HPCS), RCIC, Residual Heat Removal (RHR), and low pressure core spray (LPCS) for a 24 hour mission time;
- Incorporated realistic assessment of equipment reliability under degraded conditions post venting (the original RMIEP evaluation was conservative);
- Included a seismic PRA model (removed when the 2006A model was developed);
- Updated common cause failure (CCF) probabilities to be consistent with latest NUREG-5497 (INEL 1998) data;
- Revised the CCF probabilities of all Plant Service Water (WS) and CSCS suction strainers;
- Expanded the treatment of HRA dependencies to include additional combinations of human error probabilities (HEPs);
- Incorporated internal floods identified in RMIEP (i.e., Reactor Building floods);
- Expanded the internal flood evaluation to include potential Turbine Building flood sources;
- Incorporated unit electrical cross ties to ensure that the plant capability to respond to accidents is accurately portrayed; and,
- Included recovery of Station Air for containment venting during long term loss of decay heat removal sequences.

F.2.2.5 2000B MODEL

The 2000B model included minor enhancements. The 2000B model was an interim model and was not used to support any regulatory applications.

The 2000A and 2000B models used the same model structure and basic event databases. When the "NOT" logic was introduced in the 2000A model, the flags were not applied for the success paths in the PRAQUANT input file for the ONE4ALL model. This was corrected during the development of the 2000B model. Appropriately applying the flag settings to the success paths in the 2000B model eliminated four (4) flag basic events that had existed in the 2000A ONE4ALL logic model.

Another change in generating the 2000B model was modifying the mutually exclusive file. The overall impact on the model was insignificant.

F.2.2.6 2000C MODEL

The 2000C model incorporated changes to the 2000B model based on a revised Turbine Building flood model and an updated LSCS HRA. The 2000C CDF increased approximately 40% over the 2000B model.

F.2.2.7 2001A MODEL

The 2001A model incorporated the following changes:

- Changed the Turbine Building flood initiating event frequencies to reflect changes to the pipe inspection program;
- Revised the ATWS multipliers to agree with the findings in NUREG/CR-5500, Volume 3 (INEEL 1999);
- Changed Plant Service Water (WS) success criteria to reflect the latest operating data; and,
- Reduced the success criteria for RHR heat removal from two trains to one train provided early success of Standby Liquid Control (SBLC) injection.

F.2.2.8 2003A MODEL

The 2003A model was the result of a regularly scheduled update per the Risk Management Program. Major changes incorporated into the model included:

- Revised component failure data including extensive use of plant-specific component failure data gathered from the LSCS Maintenance Rule program;
- Revised initiating events data utilizing the latest LSCS operating experience;
- Added alternate configuration logic for all systems with alternate/standby trains;
- Added logic for newly installed redundant 125 VDC backup battery chargers on both Divisions of Unit 2;
- Added new logic for the trailer mounted Station Air compressor to the model;
- Revised Station Air success criteria (changed from one out of three compressors to any one of four compressors including the trailer mounted compressor);

F.2.2.9 2006 (A, B, AND C) MODEL

The major changes incorporated as part of the 2006A model were:

- Seismic-induced accident sequences were removed from the model (because they are outside the scope of the at-power internal events PRA)
- Modular Accident Analysis Program (MAAP) 4.0.5 code parameter file is updated to reflect:
  - the 5% LSCS Power Uprate.
  - the latest LGA[3] limit curves, e.g., heat capacity temperature limit (HCTL), PSP, PCPL, and
  - the initial pool temperature and service water temperatures are the values based on recent operating experience.

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[3] LGAs are the LaSalle specific emergency operating procedures (EOPs).

- The EOPs for LSCS (LGAs) do not direct the operators to prevent the actuation of the automatic depressurization system (ADS) (referred to as “ADS inhibit”) unless a failure to scram occurs (or power is unknown). The PRA model was modified to reflect the LGAs which differ from the generic BWROG EPGs.
- The results of the LSCS 2006 HRA FASA (Focused Area Self-Assessment) were incorporated into the 2006A model and documentation.
- An update of the TB flooding accident sequences was performed. This was subsequently revised again for the 2006B model.
- Emergency diesel generator (EDG) recovery/repair based on NUREG/CR-6890 (INEEL 2005) evaluation of data used in the loss of offsite power (LOOP)/SBO analysis was added to the LOOP/dual unit loss of offsite power (DLOOP) event sequence evaluations.
- LOOP frequency and LOOP duration based on INEEL evaluation of data in NUREG/CR-6890 (INEEL 2005) was used to characterize LSCS LOOP frequency and duration by cause category.
- Timing to core damage and time for crew response was modified to be consistent with the latest MAAP 4.0.5 calculations.
- The suppression pool cooling evaluation included both an early and late initiation to account for the time phase impacts on RCIC.
- The impact of venting and the control of the vent on the ECCS suction and RB environment were modified from the 2003A model to better represent:
  - the procedural guidance to control the vent pressure
  - the MAAP 4.0.5 assessment of net positive suction head (NPSH)
  - the MAAP 4.0.5 assessment of secondary containment environmental conditions
- The room cooling of the Residual Heat Removal Service Water/Diesel Generator Cooling Water (RHRSW/DGCW) vaults was reassessed using the latest EGC calculations. Room cooling is now required for success of these CSCS systems.
- The event trees were revised to make the vent and post containment pressure challenge RPV injection nodes more transparent.
- Performed a Bayesian update on the initiating event frequencies utilizing most recent LSCS operating experience.
- Allocated LOCA frequencies on a location and size specific basis. The LOCA locations were subdivided for more accurate assessments of their consequences.
- Initiating event fault trees were developed for the support system induced initiators of loss of TBCCW, RBCCW, and SW.
- Revised component failure data including extensive use of plant-specific component failure data gathered from the LSCS Maintenance Rule program.
- Individual component random failure probabilities Bayesian updated (as applicable) based upon the most recent plant specific data and the most current generic sources.
- CCF calculations revised to incorporate the updated individual random basic event probabilities and the most up to date Multiple Greek Letter (MGL) parameters from NUREG/CR-5497 (INEL 1998) and NUREG/CR-5485 (INEEL 1998).

- Updated maintenance unavailability data based on the most recent LSCS operating experience.
- Coincident maintenance basic events were added.
- Extensively re-assessed the HRA based on operating crew interviews using the latest training, EOPs and support procedures.
- Responded to LSCS BWROG Peer Review comments using the NEI PRA Peer Review Process.
- Performed a self-assessment against the ASME PRA Standard and resolved “gaps” to achieve Capability Category II.
- Added recirculation pump seal leakage scenarios.
- Included additional pre-initiating events in the model.
- Added alternate configuration logic for systems with alternate/standby trains.
- The conditional probability of a DLOOP given a transient or LOCA signal event was incorporated into the PRA modeling.
- RHR repair based on operating experience data was included in the evaluation.
- RCIC/LPCS room cooling was evaluated on a realistic basis and found to not be required for the accident with no gland seal failure (i.e., plant configuration with large open ventilation path exists).
- The LSCS physical location on the power grid is such that grid stability has not been shown to be a significant contributor to the LOOP and DLOOP events.

The 2006B PRA update was a follow-on to the 2006A periodic update completed in January 2007. The 2006B update addressed the following items:

- Complete revision of the internal flooding analysis
- Additional dependent HEP combinations identified and added to quantification recovery file
- The %TSW, %RBCCW, and %TBCCW initiator fault trees were quantified using the latest database and the revised frequencies were inserted into the model.

The 2006C PRA update was a follow-on to the 2006B update. During review and use of the 2006B model in the summer of 2007 to answer a site risk question, a gate error was identified in a sub-tree of the RHR suppression pool cooling logic. One of the responses to this identified error was to perform an independent review of model changes made for the 2006A and B updates. That review resulted in a number of comments. The comments ranged from non-issues (i.e., modeling correct as-is), to potential enhancements, to suggested fixes. Many of the suggested fixes and enhancements were completed, along with the suppression pool cooling (SPC) logic gate correction, for the 2006C update. The remaining comments were added to the

Updating Requirement Evaluation (URE) database for future consideration. The changes made for the 2006C update are summarized as follows:

- Revised the RHR suppression cooling fault tree gates RHR-SPC-L and RHR-SPC to address the gate error.
- Performed other fault tree logic updates on several systems to enhance the model and address self-identified issues.
- Revised the probabilities of miscellaneous CCF basic events in the database for consistency with similar events.
- Revised an initiating event frequency for a specific medium, below core LOCA.
- Input additional flood scenario links in the system fault trees that were identified in the internal flooding analysis but were not represented in the fault tree.
- Added “coincident maintenance” event links in system fault trees to reflect all the cases identified in the PRA Component Data Notebook.

F.2.2.10 2011A MODEL

The 2011A model (LS211A) was the result of a regularly scheduled update. Major changes incorporated into the model included:

- Revised component failure data including extensive use of plant-specific component failure data gathered from the LSCS Maintenance Rule program and Mitigating Systems Performance Index (MSPI).
- Bayesian updates of generic priors from NUREG/CR-6928 for both initiating events (transients) and component failures using the latest LSCS specific data.
- Refined the modeling of room cooling for the Core Standby Cooling System.
- Added the Reactor Building Ventilation (VR) check damper closure as a potential flood mitigation strategy.
- Incorporation of support system initiating event fault trees into the single top logic.
- Deletion of loss of bus 241Y and 242Y as initiating events and addition of loss of bus 241X, 242X, and 251 as initiating events.
- Converted the Human Reliability Analysis (HRA) calculations to the EPRI HRA Calculator® software platform. Minor changes in human error probabilities (HEP) were observed with this change in methodology. The HRA Calculator® was also used to facilitate the HEP dependence analysis.
- Updated maintenance unavailability data based on the most recent LSCS operating experience.
- Revised common cause failure (CCF) calculations to incorporate the updated individual random basic event probabilities and 2009 CCF parameters from INEEL (NUREG/CR-6268).
- Added a detailed pre-initiator HEP evaluation and added pre-initiators as necessary to the model.

- Deleted most of the coincident maintenance terms that had previously been added because they no longer meet the definition of the coincident maintenance as defined in the ASME/ANS PRA standard as "planned and repetitive."
- Mitigated ATWS scenarios (i.e., ATWS scenarios with successful reactivity control) with failure of containment heat removal were classified as Class IV. This was inconsistent with other EGC BWR PRAs where they were classified these as Class II (or Class I as appropriate). To address this issue, the ATWS event trees were re-evaluated and the end states were changed to Class II where appropriate. Note that the classification as Class IV was conservative with respect to the Level 2 PRA and reclassification resulted in a decrease in the large early release frequency (LERF).
- The power supplies for the station air compressors (SACs) were modified to reflect plant modifications.
- The RHR water hammer scenarios were re-evaluated as part of the 2011A model update.
- Another change was made related to the water hammer scenarios. The probability of a water hammer event causing a rupture was changed from 1E-2 to 1E-3. This probability is more consistent with industry experience and other EGC BWR PRA models.
- A change was made to the small LOCA water event tree to reflect that, for some small LOCAs, RCIC may be a viable long term injection source.
- The diesel generator recovery factors DGRECOV-4HR and DGRECOV-7HR were changed to 1.0 due to peer review comments and consistency efforts.
- The offsite power recovery factors were corrected in the model to match the values documented in LS-PSA-001 Appendix E and as given in NUREG/CR-6890.
- Multiple system fault trees and basic events were updated to address Peer Review comments and self-identified issues.
- Addressed many 2008 Peer Review findings and suggestions as tracked in the URE database. Several of these issues related to documentation. Additionally, addressed several other UREs.

F.2.2.11 2013A UPGRADE

In order to support the SAMA analysis, the LSCS LERF model was replaced by a full Level 2 model. The Level 1 logic from the 2011A model was not changed beyond what was required to integrate it with the Level 2 model.

The expansion of the LERF model to a full Level 2 model involved a reassessment of the timing and release categorization of each containment event tree (CET) endstate. To perform this reassessment, MAAP calculations for each accident class were performed and used to assess the CET endstates. Each CET node was evaluated and updated to reflect the current state of knowledge regarding Level 2 accident phenomenology. The endstate timing was also updated to reflect the current emergency plan and evacuation time estimates.

F.2.3 2013A LEVEL 1 MODEL OVERVIEW

The CDF for the 2013A model is calculated using the single top model in CAFTA at a truncation of 1E-12/yr. The 2013A Level 1 CDF is 2.58E-06/yr.

Additional details related to the 2013A Level 1 model are provided in the following subsections:

- F.2.3.1: CDF contribution by initiating event
- F.2.3.2: Contribution by accident class
- F.2.3.3: System importance measures
- F.2.3.4: Summary of the impact of asymmetries on risk

F.2.3.1 CDF CONTRIBUTION BY INITIATING EVENT

Table F.2-2 summarizes the CDF contributors by initiating event.

The turbine trip initiating event is important to note because it also represents the ATWS frequency (i.e., all ATWS events are modeled as a turbine trip). The DLOOP and LOOP are significant because they represent a major loss of mitigating events that places a high importance on the emergency diesel generators. Loss of instrument air is significant in that it causes a plant scram, main steam isolation valve (MSIV) closure, loss of containment venting capability, and loss of many balance-of-plant systems. The loss of condenser vacuum initiator causes a plant scram and loss of the power conversion system.

F.2.3.2 CDF CONTRIBUTION BY ACCIDENT CLASS

Table F.2-3 gives the definitions of the LSCS functional accident sequences. These core damage accident class definitions are consistent with the NEI guidance in NEI 91-04 (NEI 1994). Table F.2-3 also includes the 2013A model quantification of the functional classes.

The overall CDF and the distribution of the CDF among the contributing functional accident sequence classes are consistent with the significant plant mitigating system capability at LSCS.

The top 10 accident sequences are described below:

<u>Sequence #1: GTR-023 = 3.28E-7/yr (Class IIA)</u>

GTR-023 is a transient initiated loss of containment heat removal sequence.

In this sequence, SPC is not initiated (either due to operator error or hardware failure), feedwater is failed (either due to the initiator directly, operator error or hardware failure) and

HPCS is being used for core cooling. As the containment continues to heat up, the operators successfully emergency depressurize the RPV per the LGAs upon reaching the Heat Capacity Temperature Limit (HCTL). HPCS continues to be used for injection. The containment emergency vent is not initiated (due to the initiator induced failure, operator error, or hardware failure). The containment ultimately fails due to overpressurization and fails all core cooling options due to environmental impacts, resulting in a Class IIA core damage accident class.

<u>Sequence #2: DLOP-041 = 2.76E-7/yr (Class IBE)</u>

Sequence #2 is a collection of cutsets formed by different DLOOP events with the following characteristics:

- Dual unit loss of offsite power initiator or transient/LOCA induced DLOOP event
- Successful scram
- SPC is unavailable (e.g., no AC power available from EDGs)
- HPCS and RCIC fail to operate
- Low pressure coolant injection (LPCI) and LPCS are unavailable
- Offsite and onsite AC power are not recovered within 30 minutes.

These cutsets result in early core damage events with no AC power available (Class IBE).

<u>Sequence #3: ATW1-037 = 2.63E-7/yr (Class IV)</u>

This sequence is a transient initiated failure to scram (ATWS) scenario. Operators successfully lower RPV level and put HPCS in pull-to-lock per the LGAs. The main condenser is not available (e.g., operators do not bypass the MSIV low level interlock in time to prevent MSIV closure; or due to the initiator itself such as loss of service water; etc.). Motor-driven FW is used initially to provide core cooling but is not viable long-term due to inadequate hotwell inventory. However, SBLC injection fails (either due to hardware failure or operator error), resulting in a Class IV core damage accident.

<u>Sequence #4: TBRBFL-017 = 1.87E-7/yr (Class IBL)</u>

The TBRBFL-017 sequence includes the collection of all unisolated internal flooding initiating events that involve flooding of the turbine building, CSCS building, and reactor building.

The flood propagation pathway between the turbine building and reactor building is via the reactor building ventilation check dampers in the reactor building raceway at elevation 694’-6” when they are not isolated by Operations using plant procedures. The flood propagation pathway between the turbine building and the CSCS building is via the Auxiliary Building (AB) stairwell and through the door to the Division 2 CSCS room (this door is not designed to withstand floods propagating from the stairwell side of the door); and via the Division 3 switchgear room (also connected to the AB stairwell by a door not watertight for floods in the stairwell) and through another non-watertight door into the Division 3 CSCS room. The Division 1 CSCS room in each unit is protected as the doors to these rooms are watertight in both directions of water flow; however, the availability of Division 1 CSCS is irrelevant once the flood inundates the reactor building ECCS corner rooms because the primary inventory makeup system and heat removal systems are not available.

The flood progression through the Division 3 CSCS switchgear rooms is assumed to result in a DLOOP due to flood impacts on the system auxiliary transformer (SAT) breaker cubicles feeding the Division 3 switchgear. Reactor scram is successful; however, RCIC and HPCS fail to provide initial core cooling. The ADS system with LPCS or LPCI injection is used for initial core cooling. In these sequences, Operations fail to align fire protection for long term RPV alternate injection resulting in a Class IBL core damage accident.

All of the significant contributors, however, are associated with fire protection system breaks within the reactor building that lead to ECCS failure.

<u>Sequence #5: GTR-013 = 1.58E-7/yr (Class IIA)</u>

GTR-013 is a transient initiated loss of containment heat removal sequence.

In this sequence, SPC is not initiated (either due to operator error or hardware failure), feedwater is successful, but the main condenser is not available (either due to the initiator directly, operator error or hardware failure). As the containment continues to heat up, the operators successfully emergency depressurize the RPV per the LGAs upon reaching the Heat Capacity Temperature Limit (HCTL). FW continues to be used for injection. The containment emergency vent is not initiated (either due to the initiator directly, operator error or hardware failure). The containment ultimately fails due to overpressurization and fails all core cooling options due to environmental impacts, resulting in a Class IIA core damage accident.

<u>Sequence #6: DLOP-014 = 1.35E-7/yr (Class IIA)</u>

Sequence #6 is a collection of cutsets formed by different DLOOP events with the following characteristics:

- Dual unit loss of offsite power initiator or transient/LOCA induced DLOOP event
- Successful scram
- SPC is unavailable (e.g., no AC power available from EDGs)
- HPCS is successful and the RPV is successfully depressurized
- Containment heat removal is unavailable and ultimately fails all injection
- Offsite and onsite AC power are not recovered within 30 minutes.

These cutsets result in core damage events with no containment heat removal (Class IIA).

Sequence #7: ATW1-031 = 9.78E-8/yr (Class IC)

This sequence is a transient-initiated failure to scram (ATWS) scenario. Operators successfully lower RPV level and put HPCS in pull-to-lock per the LGAs. The main condenser is not available (e.g., operators do not bypass the MSIV low level interlock in time to prevent MSIV closure; or due to the initiator itself such as loss of service water; etc.). Motor-driven FW is used initially to provide core cooling but is not viable long-term due to inadequate hotwell inventory. Operators successfully inhibit ADS and successfully control RPV level during the SBLC injection process. However, following hotwell depletion, RPV emergency depressurization is not performed in a timely manner (either due to operator error or hardware failure) to allow low pressure injection to provide adequate core cooling. This scenario leads to a Class IC core damage accident.

Sequence #8: GTR-011 = 8.72E-8/yr (Class IIV)

In this sequence, SPC is not initiated (either due to operator error or hardware failure), feedwater is successful, but the main condenser is unavailable (either due to the initiator directly, operator error or hardware failure). As the containment continues to heat up, the operators successfully emergency depressurize the RPV per the LGAs upon reaching the Heat Capacity Temperature Limit (HCTL). FW continues to be used for injection. The containment emergency vent is initiated; however, containment venting results in failure of all injection sources post venting, resulting in a Class IIV core damage accident.

Sequence #9: ATW1-032 = 7.71E-8/yr (Class IV)

This sequence is a transient initiated failure to scram (ATWS) scenario. Operators successfully lower RPV level and put HPCS in pull-to-lock per the LGAs. The main condenser is not available (e.g., operators do not bypass the MSIV low level interlock in time to prevent MSIV closure; or due to the initiator itself such as loss of service water; etc.). Motor-driven FW is used initially to provide core cooling but is not viable long-term due to inadequate hotwell inventory. In these scenarios the operators either fail to inhibit ADS or control RPV level late in the sequence. This scenario leads to a Class IV core damage accident.

Sequence #10: ILOC-009 = 7.59E-8/yr (Class V)

This sequence is an unisolated break outside of containment. After a successful scram, operators fail to isolate the rupture, resulting in a Class V core damage accident.

F.2.3.3 SYSTEM IMPORTANCE MEASURES

The LSCS PRA utilizes three industry standard risk importance measures to put the importance of components, trains, functions, initiating events (IE), HEPs, etc. into perspective:

- Fussell-Vesely (F-V) is the fractional contribution of the specific element in question (component, train, system, function, IE, or HEP) to the total risk. The F-V importance calculation is generally in the form of a fractional number that may be directly translated into a percentage contribution to risk. For example, 0.0230 or 2.3E-02 may be directly translated into a 2.3% contribution to risk.
- Risk Achievement Worth (RAW) is the factor by which the risk would increase if the specific element in question (component, train, system, function, IE, or HEP) is assumed to fail. For example, if a component, train, system, function or HEP has a RAW of 2.0, the calculated risk would double if the event were assumed to have a failure probability of 1.0.
- Risk Reduction Worth (RRW) is the factor by which the risk would decrease if the component, train, system, function, IE, or HEP is assumed to be perfectly reliable (i.e., if its probability of failure were zero).

Risk importance measures reflect the degree of contribution that a system or train's failure has to the current assessment of risk (Fussell-Vesely) or how greatly risk would be increased by the guaranteed failure of a train or system (RAW). These importance measures can be different for the different trains of a system or different among seemingly similar systems. Such asymmetries reflect the fact that system and train importance determinations for the LSCS risk profile are affected by a number of factors. The three principal factors are:

- Plant design features that create higher importance for certain systems and trains
- Masking of system or train importance by other failures
- Modeling asymmetries (including pumps assumed normally operating)

Figure F.2-1 shows the relative importance of system, train, or component importance to LSCS Unit 2 CDF using the Fussell-Vesely importance measure.

Figure F.2-2 shows the relative importance of system, train, or component importance to LSCS Unit 2 CDF using the RAW importance measure.

F.2.3.4 SUMMARY OF THE IMPACT OF ASYMMETRIES ON RISK

The principal plant design feature asymmetries impacting the LSCS risk profile are:

- AC and DC Divisions 1, 2, and 3 support substantially different equipment;
- AC Division 1 does not have a dedicated diesel generator (DG) and may require operator action to share the DG between both units;
- DC Divisions 1 and 2 have the safety relief valves (SRVs) plus support instrumentation and control of their associated AC divisions;
- C RHR is not a heat removal train, whereas A and B RHR are capable of suppression pool cooling and shutdown cooling;
- LPCS, A RHR, and RCIC are on Division 1;
- B and C RHR are on Division 2;
- The RCIC/LPCS room and the A RHR room share a common floor drain, without a check valve, which results in flood water propagating between both rooms;
- LPCS does not require room cooling for the 24 hour mission time, but RHR and HPCS do require room cooling; and
- Plant service water (WS (system designator), also referred to as SW in PRA document discussions) Unit 0 swing pump 0WS01P is powered from Unit 2 4.16 kVAC switchgear 241X.

F.2.4 2013A LEVEL 2 MODEL OVERVIEW

The core damage frequency (CDF) model provides a tool for estimating the likelihood or frequency of core damage. Because consequences of a core damage event can range from minimal (as in the case of the Three Mile Island event in 1979) to more severe (as in the case of the Fukushima event in 2011), additional information is needed to assess risk. Therefore, the Level 2 PRA model is designed to identify underlying causes of containment failure for severe accidents and the associated release pathways and their frequencies. Specifically, the Level 2 PRA determines the release frequency, severity, and timing of postulated releases based on the Level 1 PRA, accident progression analysis, and containment performance.

The Level 2 PRA includes two types of analyses: (1) a deterministic analysis of the physical processes for a spectrum of severe accident progressions, and (2) a probabilistic analysis component in which the likelihood of the various outcomes are assessed. The deterministic analysis examines the response of the containment to the physical processes associated with a severe accident. Containment response is modeled by: (1) using the MAAP4 code to simulate severe accidents that have been identified as dominant contributors to core damage in the Level 1 analysis, and (2) performing reference calculations for hydrodynamic and heat transfer phenomena that occur during the progression of a severe accident.

The Level 2 PRA is based on a containment event tree (CET) model. The CET represents an accident progression given initial plant damage states and is a logic model with functional nodes that represent sequential phenomenological events and the status of containment protection systems. The CET provides the framework for evaluating containment failure modes and conditions that would affect the magnitude of the release.

The LSCS CETs allow core damage scenarios defined in the Level 1 model to be further developed into consequence bins. Separating scenarios this way allows results of plant risk calculations to be presented in simple, meaningful terms. Consequence bins are based on the severity of the source term and the timing of the release relative to the time a general emergency is declared and then initiation of protective actions for the public. The characteristics of these bins are then used as input for the Level 3 model. The following subsections summarize the breakdown of the bins and the Level 2 results.

F.2.4.1 CONSEQUENCE BINS: SOURCE TERM SEVERITY

The radionuclide release categories are defined based on two parameters: timing and severity. Timing of the release for each sequence is based on MAAP calculations of the sequence chronology. The classification of release magnitude is also based on MAAP 4.0.5 calculations.

The inputs for determining the plant specific characteristics of the radionuclide release bins are the following:

- The Level 1 PRA
- The MAAP 4.0.5 plant specific calculations
- The LSCS Emergency Plan and Emergency Action Levels (EALs)
- The magnitude of releases that can contribute to public health effects
- The evacuation timing

The magnitude of the radionuclide releases for purposes of binning sequences is characterized in terms of the radionuclide release fraction for CsI, which is a dominant contributor to both prompt and latent health effects. The CsI release fraction also correlates well with other contributors to offsite effects. For consequence calculations, additional radionuclides are included as inputs to the release.

The bins used to define the release magnitude spectrum are as follows:

Characterization	Designator	CsI Release Fraction
High	H	> 10%
Medium	M	> 1% and ≤ 10%
Low	L	> .1% and ≤ 1%
Low-Low	LL	≤ .1%

The resulting definitions of the radionuclide release end states are summarized in Table F.2-4.

Using the MAAP results and the Level 2 containment event trees, the radionuclide release categories can be assigned to each CET sequence end state. When MAAP is not well suited to modeling the accident phenomena associated with a scenario, the scenario is modeled using conservative estimates (e.g., steam explosion) and insights from other Level 2 PRA models from plants of a similar type.

F.2.4.2 CONSEQUENCE BINS: TIMING OF RELEASE

Each sequence that leads to a radioactive release from containment is classified as “early”, “intermediate”, or “late”. This designation is intended to reflect mitigation of consequences by evacuating people from the area, as appropriate. The “early” classification is used for scenarios in which a radioactive release occurs before the evacuation of the 10 mile Emergency Planning Zone (EPZ) is assumed to be complete. Based on the Evacuation Time Estimate (ETE) study (ARCADIS 2012), the worst case conditions (weather, etc.) correlate to a 10 mile EPZ evacuation time of 5 hours from the point when a general emergency (GE) is declared. The “Early” scenarios, therefore, are those scenarios in which a radioactive release occurs within 5 hours of the time that a GE is declared. Releases occurring between 5 and 24 hours from the declaration of a GE are categorized as “intermediate”. Releases occurring at times greater than 24 hours after the declaration of a GE are considered “late”. Release timing is summarized in Table F.2-4, which is reproduced from the LSCS Level 2 model documentation.

F.2.4.3 LEVEL 2 PRA RADIONUCLIDE RELEASE CATEGORIES

Classifications of radionuclide releases need to be adequate to distinguish the severe accident scenarios that can result in potentially high public consequences versus those that have public consequences below measurable values. Therefore, the LSCS PRA model has been expanded to be a full Level 2 model with a spectrum of radionuclide release categories. This knowledge of consequences, coupled with the quantification of the accident sequence frequencies, allows for the characterization of the public risk and the identification of potentially cost-beneficial plant or procedure modifications.

As mentioned previously, the source terms associated with each of these release severity categories are quantified through the use of LSCS-specific calculations. A review of existing consequence analyses performed in previous and current PRAs was also performed to confirm the reasonableness of the radionuclide release values.

The frequency of radionuclide release is characterized by the quantification of the Level 1 and Level 2 PRA models. The Level 2 radioactive release frequency event tree end states are delineated by the magnitude and timing bins of the calculated radionuclide release, as described above. Therefore, the CET end states are characterized using a two-term matrix (severity, time) as shown in Table F.2-5.

Tables F.2-4 and F.2-5 provide the nomenclature used in the definition of radionuclide release categories. Table F.2-6 provides a quantitative summary of the radioactive release frequency event tree results. For each of the release categories from Table F.2-5, the corresponding frequency is provided. Table F.2-6 provides quantitative information that is useful in the interpretation of the current containment capability given the spectrum of core damage sequences calculated in the Level 1 PRA.

The quantification provides a method with which to measure the best estimate of containment performance given that severe accidents could progress to beyond core damage. The quantification may include some conservatism to account for the limitations of current models and experiments to predict certain severe accident-related phenomena (e.g., ATWS is always assumed to result in a large containment failure).

A fraction (approximately 29 percent) of the core damage accidents transferred from Level 1 PRA are effectively mitigated, such that releases are essentially contained within an intact containment (i.e., INTACT release bin). In addition, only about 5.5 percent of the postulated accidents lead to “large” releases occurring before protective action can be taken (i.e., approximately 5.5 percent of the accidents result in LERF).

Figure F.2-3 is a histogram that compares the total core damage frequency (i.e., the results of the Level 1 PRA) with the frequencies for each of the release categories from Level 2. A substantial fraction of the core damage frequency (approximately 50 percent) lead to “small” (low or low-low) or negligible (i.e., INTACT) categories from Level 2.

F.2.5 PRA QUALITY

The 2013A update to the LS PRA model is the most recent evaluation of the risk profile at LSCS for internal event challenges (LS213A). This PRA model is documented as an application-specific model developed for the use in the SAMA risk-informed application. The current PRA model of record is the 2011A PRA. The CDF portions of the 2011A and 2013A PRA models are identical. The 2011A model is a LERF-only model while the 2013A PRA model is expanded to include a full Level 2 model. The LERF results for the 2011A and 2013A PRA models are similar; and the 2013A model provides a detailed risk categorization of release bins and timing for all release categories, in addition to the large early release category.

The LS PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause events. The PRA model quantification process used for the LS PRA is based on the event tree / fault tree methodology, which is a well-established methodology in the industry.

EGC employs a multi-faceted approach to establishing and maintaining the technical adequacy and plant fidelity of the PRA models for all operating EGC nuclear generation sites. This approach includes both a proceduralized PRA maintenance and update process, and the use of self-assessments and independent peer reviews. The following information describes this approach as it applies to the LSCS PRA.

F.2.5.1 PRA MAINTENANCE AND UPDATE

The EGC risk management process ensures that the applicable PRA model remains an accurate reflection of the as-built and as-operated plants. This process is defined in the EGC Risk Management program, which consists of a governing procedure (ER-AA-600, "Risk Management") and subordinate implementation guidelines. The overall EGC Risk Management program defines the process for implementing regularly scheduled and interim PRA model updates, for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, industry operating experience), and for controlling the model and associated computer files. To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plants, the following activities are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model.
- New engineering calculations and revisions to existing calculations are reviewed for their impact on the PRA model.
- Maintenance unavailabilities are captured, and their impact on CDF is trended.
- Plant-specific initiating event frequencies, failure rates, and maintenance unavailabilities are updated approximately every four years.

In addition to these activities, EGC risk management procedures provide the guidance for particular risk management and PRA quality and maintenance activities. This guidance includes:

- Documentation of the PRA model, PRA products, and bases documents.
- The approach for controlling electronic storage of Risk Management (RM) products, including PRA update information, PRA models, and PRA applications.
- Guidelines for updating the full-power, internal events PRA models for EGC nuclear generation sites.
- Guidance for use of quantitative and qualitative risk models in support of the On-Line Work Control Process Program for risk evaluations for maintenance tasks (corrective maintenance, preventive maintenance, minor maintenance, surveillance tests and modifications) on systems, structures, and components (SSCs) within the scope of the Maintenance Rule (10 CFR 50.65(a)(4)).

In accordance with this guidance, regularly scheduled PRA model updates nominally occur on an approximately four-year cycle; shorter intervals may be required if plant changes, procedure enhancements, or model changes result in significant risk metric changes. In addition, EGC now maintains a continuous updated model to ensure the risk assessment of the as-built, as-operated plant does not deviate significantly from the model of record.

F.2.5.2 APPLICABILITY OF PEER REVIEW FINDINGS AND OBSERVATIONS

Several assessments of technical capability have been made, and more are planned for the LSCS PRA model. The completed assessments are summarized in the paragraphs below.

- An independent PRA peer review was conducted under the auspices of the BWR Owners' Group in July 2000, following the Industry PRA Peer Review process (BWROG 1997). This peer review included an assessment of the PRA model maintenance and update process. All findings from this peer review were addressed and closed out.
- During 2005 and 2006, the LSCS PRA model results were evaluated in the BWR Owners' Group PRA cross-comparisons study performed in support of implementation of the

mitigating systems performance indicator (MSPI) process. No significant issues resulted from this comparison.

- A self-assessment analysis was performed using Agenda B of the ASME PRA Standard (ASME 2005) and Regulatory Guide 1.200, Rev. 1 (NRC2007a) as part of the periodic update of the LSCS PRA. This was updated and finalized to represent the current status near the completion of the update in 2007.
- A PRA Peer Review of the LSCS PRA was performed during the spring of 2008 (in accordance with the NEI Peer Review process). The results of the PRA Peer Review indicated that a small number of the supporting requirements (SRs) were "Not Met" or met only at the Capability Category I. However, many of these SRs related principally to documentation and the treatment of modeling uncertainty. The results of the LSCS PRA Peer Review support the quality of the LSCS PRA and its use for the SAMA analysis.

A PRA update was conducted in 2011 and addressed the majority of 2008 peer review findings and ASME/ANS PRA Standard supporting requirements assigned a Capability Category II or lower. Table F.2-7 provides a summary of the open findings and supporting requirements assigned a capability category II or lower and a discussion of the potential impact on the SAMA analysis. "Open" items, or those that have not been "closed out", are issues that are still being tracked and have not yet had their dispositions finalized through the ER-AA-600-1015 process. As documented in Table F.2-7, the impact of resolving the "open" items would have a negligible impact on the SAMA analysis.

F.2.5.3 CONSISTENCY WITH APPLICABLE PRA STANDARDS

As indicated above, a formal peer review was performed in the spring of 2008 and the final peer review report issued in July 2008. This peer review was performed against Addendum B of the PRA Standard (ASME 2005), the criteria in RG-1.200, Rev. 1 (NRC 2007a), including the NRC positions stated in Appendix A of RG-1.200, Rev. 1 and further issue clarifications (NRC 2007b). The remaining open supporting requirements (SRs) identified from the peer review as not meeting Capability Category II and associated findings are summarized in Table F.2-7 along with an assessment of the impact on the base PRA.

F.2.5.4 PRA QUALITY SUMMARY

The LSCS PRA maintenance and update processes and technical capability evaluations described above provide a robust basis for concluding that the PRA is suitable for use in this risk-informed application.

F.3 LEVEL 3 RISK ANALYSIS

The Level PRA 3 combines the Level 2 PRA results with site-specific parameters (e.g., population distribution, meteorological data, land use data, and economic data) to estimate offsite public dose and offsite economic consequences of the postulated releases to the environment. This section addresses the key input parameters and analysis of the Level 3 portion of the risk assessment. In addition, Section F.7.3 summarizes a series of sensitivity evaluations to potentially critical input parameters.

F.3.1 ANALYSIS

The MACCS2 code (NRC 1998), version 1.13.1, was used to perform the Level 3 probabilistic risk assessment (PRA) for LSCS. The MACCS2 code was developed to support probabilistic risk assessments (NRC 1998) and is the standard code used to calculate off-site population dose and economic costs in support of a SAMA analysis, as recognized in NEI 05-01 (NEI 2005). The atmospheric transport and dispersion (ATD) straight-line Gaussian plume segment model incorporated in MACCS2 has been compared against more sophisticated, variable trajectory ATD models, such as the three-dimensional ADAPT/LODI code, and shown to be acceptable for the purposes of typical MACCS2 code applications (NRC 2004b).

For the LSCS MACCS2 analysis, the input parameter values used in NUREG-1150 (NRC 1990a), as detailed in NUREG/CR-4551 (NRC 1990b) and reflected in the MACCS2 "Sample Problem A," (NRC 1998) formed the initial bases in addition to those utilized in the LSCS Unit 2 Risk Methods Integration and Evaluation Program (RMIEP) as documented in the NUREG/CR-5305 volumes (NRC 1992c). NUREG-1150 is a seminal work in PRA performed by the NRC and the national laboratories that includes a Level 3 PRA for five different reactor sites. It was subjected to extensive peer review and has been accepted by the NRC as a standard reference for MACCS2 inputs for SAMA analyses. The RMIEP study is a LSCS-specific risk analysis study that includes a Level 3 (MACCS2) analysis. Where applicable, the initial values from these sources were replaced with updated site-specific values applicable to LSCS and the surrounding region. Site-specific data included, for example, population distribution, certain economic parameters such as property value of farm and non-farm land, and meteorological data. Standardized economic parameters from the NUREG-1150 study for the costs of evacuation, relocation and decontamination were escalated from the time of their formulation (1986) to reflect more recent (July 2013) costs. Plant-specific release data included release frequencies and the time-dependent distribution of nuclide releases from eight (8) accident sequences at LSCS. The behavior of the population during a release (as modeled through evacuation parameters) was based on plant and site-specific set points (i.e., declaration of a General Emergency) and evacuation time estimates (ARCADIS 2012). These data were used in combination with site-specific meteorology to calculate risk impacts (exposure and economic) to the surrounding population within a 50 mile radius of LSCS.

F.3.2 POPULATION

The population surrounding the LSCS site is estimated for the year 2043, the last year of projected operation for Unit 2 given a 20 year license extension (Unit 1 license expires in 2042). Estimating the population of the SAMA analysis region entailed three major steps: (1) determining the year 2000 permanent population within a 50-mile radius of LaSalle; (2) accounting for the transient population within the SAMA analysis region; and (3) projecting that permanent and transient population out to the year 2043 based on available population projection data.

The population distribution projection was based on year 2000 census data available via SECPOP2000 (NRC 2003). A comparison to 2010 census data has been performed. The baseline resident year 2000 population from SECPOP2000 was determined for each of 160 grid elements of a polar coordinate grid consisting of sixteen directions (i.e., N, NNE, NE,…NNW) for each of ten concentric distance rings with outer radii at 1, 2, 3, 4, 5, 10, 20, 30, 40 and 50 miles surrounding the site. Transient population data from the LSCS Evacuation Time Estimate (ETE) study (ARCADIS 2012) for the approximate 10-mile radial area around the site were added to the SECPOP permanent population, consistent with the guidance of NEI 05-01 (NEI 2005), on a grid element basis. In addition to the ETE category of transient population (which includes employees), seasonal residents and special facilities[4] populations derived from the LaSalle ETE study (ARCADIS 2012) were also included in the initial year 2000 population estimate.

To estimate growth rates, Illinois county population projection data for the year 2030 were used. Table F.3-1 presents the county growth rates for the years 2000 to 2030. Individual growth rates were calculated for each grid element based on the county growth rate and the proportion of land in each grid element associated with the applicable counties. The combined resident

[4] In this analysis, special facilities include medical, nursing care, and correctional facilities as well as schools and day cares. These facilities require special considerations for evacuation of the population.

and transient data (including seasonal residents and special facilities) were projected from year 2000 to 2030, and then from 2030 to 2043 (using the year 2000 to 2030 growth rate times a 0.433 factor, i.e., 13/30) to calculate the 2043 population distribution.

Table F.3-2 presents the year 2000, projected year 2010, and year 2010 census population for the counties surrounding LSCS and demonstrates that use of the Census 2000 data in combination with projected county growth rates rather than Census 2010 data in the analysis is reasonable and slightly conservative (i.e., the projected data shows a slightly higher total population relative to that estimated using the Census 2010 data). Table F.3-3 presents the year 2000 transient (including employees) and special facility population within 10 miles of the LSCS. Table F.3-4 presents the year 2000 residential population within 50 miles of the LSCS site. Table F.3-5 presents the year 2010 projected population including transient, seasonal resident, and special facilities and provides a basis for comparing other 2010 population estimates developed to support the LSCS license extension.

The total year 2043 population for the 160 grid elements in the region is estimated at 3,107,897. The distribution of the population is given for the 10-mile radius and the 50-mile radius from LSCS in Tables F.3-6 and F.3-7, respectively.

F.3.3 ECONOMY

MACCS2 requires certain agricultural and land-based economic data (fraction of land devoted to farming, annual farm sales, fraction of farm sales resulting from dairy production, and property value of farm and non-farm land) for each of the 160 grid elements. This data can be generated by SECPOP2000 (NRC 2003), but due to known issues associated with the economic parameter processing portion of the SECPOP2000, SECPOP2000 was not utilized to develop the county-specific economic values for the LSCS analysis. The issue in question only impacts economic data and does not affect population output of the SECPOP2000 code. Instead, the economic values were developed manually following the SECPOP calculation approach documented in NUREG/CR-6525 (NRC 2003) using data from the 2007 National Census of Agriculture (USDA 2009) and 2007 data (for consistency with the census of agricultural data) from the Bureau of Economic Analysis (BEA 2013) for each of the 21 counties surrounding the plant, to a distance of 50 miles. Economic values were updated to July 2013 using the consumer price index (CPI) from the Bureau of Labor Statistics (BLS 2013). The values used for each of the 160 grid elements were the data from each of the surrounding counties multiplied by the fraction of that county's area that lies within that sector. Region-wide wealth data (i.e., farm wealth and non-farm wealth) were based on county-weighted averages for the region within 50-miles of the site using the same economic data sources. Spatial elements within the same county have the same index value. Spatial elements involving multiple counties have unique index values. The portion of each county within 50-miles of the site was accounted for in the calculation. The fraction of each spatial element that is land (as opposed to water) was visually estimated using maps and images of the regions surrounding LSCS and was also taken into consideration. Region index values were assigned based on application of the county-level data to a 50-mile radius grid surrounding each site. Data from the 2007 Census of Agriculture (USDA 2009) was used to determine the farmland fraction for each of the counties surrounding LSCS. County-specific land use and related economic parameter values are summarized in Table F.3-8.

In addition, generic standardized economic data values that are applied to the region as a whole were adjusted from the NUREG-1150 based data to account for cost escalation since 1986, the year those input values were first specified. A factor of 2.13, representing cost escalation from 1986 (CPI index of 109.6) to July 2013 (CPI index of 233.6) was applied to parameter values describing cost of evacuating and relocating people and decontamination activities. The use of appropriately escalated standardized economic parameter values from NUREG-1150 is consistent with NEI 05-01 guidance and previous NRC-approved SAMA analyses for other nuclear power plants seeking renewed operating licenses.

MACCS2 standardized economic parameter values utilized in the LSCS analysis are summarized in Table F.3-9.

F.3.4 FOOD, AGRICULTURE, AND WATERSHED

Food ingestion is modeled using the new MACCS2 ingestion pathway model COMIDA2, consistent with MACCS2 User's Guide (NRC 1998). The COMIDA2 model utilizes national based food production parameters derived from the annual food consumption of an average individual such that site specific food production values are not utilized. Annual dose limits trigger crop or milk disposal, as appropriate. Values are chosen consistent with the most recent guidance of FDA 63 FR-43402 (FDA 1998). These parameters and their values used in the LSCS analysis are presented in Table F.3-10. The fraction of population dose due to food ingestion is typically small compared to other population dose sources. For LSCS, MACCS2 results indicate that approximately 2.7% of the total population dose is due to food ingestion for the base case.

Spatial elements are designated as river systems or lake systems. Per NUREG/CR-4551 (NRC 1990b) the designation of lake is only used for very large bodies of water, such as Lake Michigan, which may serve as drinking water sources. Lake Michigan is outside the 50-mile radius region. The other lakes around the LSCS site are smaller and are expected to behave like river systems.

F.3.5 NUCLIDE RELEASE

The core inventory at the time of the accident is based on a plant-specific calculation (Exelon 2011). The core inventory represents bounding isotopic values for 100 effective full power days (EFPD) or 711 EFPD (end-of-cycle) for LSCS operating at 3489 MWt. The current licensed core power level is 3546 MWt based upon a recent power uprate associated with measurement uncertainty recapture (MUR). The MACCS2 model includes a reactor power scaling factor of 1.0163 (i.e., 3546 MWt/3489 MWt) to address the MUR power uprate to 3546 MWt. Table F.3-11 summarizes the estimated LSCS core inventory used in the MACCS2 analysis.

Wake effect data are based on LSCS Reactor Building dimensions. The top of the Reactor Building structure is 184 ft. (56.1 m) above grade. The average outer width of the combined Reactor Building structure is 217 ft. (66.1 m). Plume standard deviations sigma-y and sigma-z are based on MACCS2 User's Guide formulas (NRC 1998).

LSCS nuclide radioisotope groups, as represented using the MAAP computer code version 4.0.5, are related to the MACCS2 radioisotope groups as shown in Table F.3-12. MAAP 4.0.5 is a computer code used to predict source terms resulting from severe accidents. Thirteen (13) different source-term categories were developed in the LSCS Level 2 PRA, shown in Table F.3-13. These release categories represent a radionuclide release severity and timing classification as shown in Table F.3-14. A separate release category for a break outside containment (BOC) is included with the categories. The thirteen (13) release categories were grouped into eight (8) release bins as shown in Table F.3-15. The frequency of each release bin is shown in Table F.3-16.

For each of the eight (8) release bins, a representative MAAP case was chosen based on a review of the Level 2 model cutsets and the dominant types of scenarios that contribute to the release category. MAAP cases were not required for the High/Late, Moderate/Late, Low/Late, or any of the Low-Low release categories due to negligible frequency in the Level 2 analysis (LS213A). Brief descriptions of each release category, dominant Level 2 sequences, frequency of the release category, and the representative MAAP case are provided in Table F.3-17. It should be noted that the release category reference MAAP cases in the Level 2 analysis are used along with the Level 2 release category rules to assign an appropriate end state to the Level 2 sequence. A summary of the representative MAAP cases (i.e., key case timings) is shown in Table F.3-18.

Consistent with the NEI 05-01 guidance (NEI 2005), a plume release height of 28 m (92 ft.) above grade is used to represent a release from the mid-height of the containment. Buoyant plume rise is modeled assuming a thermal plume heat content of 10 MW for all releases except intact containment (where zero heat content is assumed). A value of 10 MW bounds typical values in NUREG/CR-4551 (NRC 1990b). Assumptions associated with release height and plume heat content are considered in the sensitivity analyses, presented in Section F.7.3.

Representative MAAP cases were run until plateaus of the CsI and CsOH release fractions were achieved. Experience has shown that CsI is a primary contributor to early dose, and CsOH is a primary contributor to late dose and cleanup costs.

Multiple release duration periods (i.e., plume segments) were defined and represent the time distribution of each category's releases. A summary of the release magnitude and timing for those cases is provided in Table F.3-19.

A dry deposition velocity of 0.01 m/sec is used for the MACCS2 analysis, consistent with the NRC's recommendation as documented in the MACCS2 Sample Problem A (NRC 1998). The dry deposition velocity is evaluated in the sensitivity analysis, presented in Section F.7.3.

F.3.6 EVACUATION AND SHIELDING AND PROTECTION

Reactor trip for each sequence is taken as time zero relative to the core containment response times. A General Emergency (GE) is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public. For the LSCS analysis, the time of the GE declaration is estimated based on the LSCS emergency action levels (Exelon 2013). The declaration times are presented in Table F.3-19. For most release categories, the GE time is established as the time of core damage. However, a minimum GE time of 30 minutes is used for release categories with core damage projected to occur in less than 30 minutes.

Ninety five percent of the population within 10 miles of the plant (Emergency Planning Zone, EPZ) is assumed to evacuate and 5 percent is assumed not to evacuate, consistent with guidance in the MACCS2 User's Guide (NRC 1998). These values are conservative relative to the NUREG-1150 study (NRC 1990a), which assumed evacuation of 99.5 percent of the population within the EPZ.

The evacuees are assumed to begin evacuation 100 minutes after a general emergency has been declared at a base evacuation radial speed of 1.6 m/sec. A time of approximately 4.4 hours is used to model evacuation of the 10-mile EPZ, based on weighting the ETE times to account for the season (i.e., winter vs. summer), time of the week (i.e., midweek vs. weekend), time of day (i.e., daytime vs. nighttime), and weather conditions (i.e., fair vs. adverse). The ETE study does not present any specific event (e.g., festival) evacuation time estimates.

The time to begin evacuation and the base speed are derived from the site-specific evacuation study (ARCADIS 2012). The evacuation parameters were considered further in the sensitivity analyses presented in Section F.7.3.2.

The ETE study evacuation times range from 3 hours and 50 minutes (for winter, nighttime, and fair conditions) to 5.0 hrs. (for winter, midweek, daytime, and adverse conditions or winter, nighttime, and adverse conditions) for a 100% evacuation of the 10 mile EPZ. These ETE times include "shadow evacuation" of 20% of the residential population outside the 10 mile EPZ, to a distance of 15 miles.

Shielding and exposure factors were chosen consistent with those developed and used in the NUREG-1150 (NRC 1990a) studies and the Integrated Risk Assessment for LSCS Unit 2 as documented in NUREG/CR-5305 (NRC 1992).

F.3.7 METEOROLOGY

Annual hourly meteorology LSCS data sets from 2010 through 2012 were processed for use in the MACCS2 analysis. These data sets were obtained from onsite meteorological stations. No additional offsite meteorological data were used with the exception of mixing layer height.

The meteorological file used as input into the MACCS2 code consists of one (1) year of hourly recordings (8760) of accumulated precipitation. When precipitation occurs during a release, the depletion of the plume occurs more rapidly due to plume washout. The amount of plume washout is proportional to the intensity and duration of precipitation. The MACCS2 code does not differentiate between rain and snow precipitation.

Of the hourly data of interest (10-meter wind speed, 10-meter wind direction, multi-level temperatures used to calculate stability class, and precipitation), 2% or less of the data were missing for each of the three years of data. Traditionally, up to 10% of missing data is considered acceptable (NRC 2007c). MACCS2 requires complete sequential hourly data for the full year, therefore missing data must be estimated. The percentages of data hours that included estimated data for missing data for years 2010, 2011, and 2012 were 2.0%, 1.6%, and 1.1%, respectively. Data gaps were filled in the following manner (order of priority):

- Wind speed and wind direction were taken from the 33-ft (~10m) sensor of the primary site tower. If wind direction data from the 33-ft sensor was not available, wind direction data was taken from the 200-ft sensor or the 375-ft sensor. If wind speed data from the 33-ft sensor was 77.7 (flag for calm), then 0.5 mph was used as a surrogate.
- Gaps containing less than six consecutive hours of missing data were filled by interpolation.
- Gaps containing six or more consecutive hours of missing data were filled by substitution from previous or following data (same time of day). For wind speed, the power law (see next bullet) was used prior to this approach, if possible.
- If wind speed data had six or more consecutive hours of data missing, the power law was used to determine the beta factor for the two rows of data immediately before and after the missing data rows and then the beta factor was averaged and used to estimate the wind speed for the missing hours. (This was only required for 2012 meteorological data.)

The 10-meter wind speed and direction were combined with precipitation and atmospheric stability (derived from the vertical temperature gradient) to create the hourly data file for each year for use by MACCS2.

The 2012 data set was found to result (see Section F.7.3.1 for discussion of sensitivity analysis) in the largest economic cost risk and dose risk compared to the 2010 and 2011 data sets. Therefore, the 2012 hourly meteorology was selected as the base case.

The MACCS2 code requires morning and afternoon mixing layer heights to be defined in the meteorological file for the four (4) seasons of the year. For a given season, MACCS2 uses the larger of the two values. The start day of each weather sequence determines the season in which that sequence lies. These values ranged from 310 meters to 1550 meters, as documented in the Holzworth data (EPA 1972).

F.3.8 MACCS2 RESULTS

Table F.3-20 shows the mean off-site doses and economic impacts to the region within 50 miles of LSCS for each of eight (8) release categories calculated using MACCS2. The mean off-site dose impacts are multiplied by the annual frequency for each release category (see Table F.3-15) and then summed to obtain the dose-risk and offsite economic cost-risk (OECR) for each unit.

Table F.3-20 indicates that the total dose-risk is approximately 7.11 p-rem/yr. The total OECR is calculated to be about 53,400 \$/yr. The largest contributor to these results is the moderate/intermediate release category which accounts for approximately 50% of the dose risk and 61% of the cost risk.

F.4 BASELINE RISK MONETIZATION

This section explains how LSCS calculated the monetary value of the status quo (i.e., accident consequences assuming no mitigation due to SAMA implementation). LSCS also used this analysis to establish the maximum benefit that could be achieved if all on-line LSCS risk were eliminated, which is referred to as the Maximum Averted Cost-Risk (MACR). Per the site PRA model (designated LS213A), the Unit 2 internal events CDF of 2.58E-06 (at a truncation of 1E-12/yr) was used for the calculations in the following sections. External risk is addressed in Section F.4.6.2.

F.4.1 OFF-SITE EXPOSURE COST

The baseline annual off-site exposure risk was converted to dollars using the NRC's standard conversion factor of \$2,000 per person-rem, and discounted to present value using the following NRC standard formula (NRC 1997):

$$Wpha = C \times Zpha$$

Where:

W_{pha} = monetary value of public health accident risk after discounting

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

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

r	=	real discount rate (RDR) (as fraction) = 0.03 per year
Z_{pha}	=	monetary value of public health (accident) risk per year before discounting ($ per year)

The Level 3 analysis showed an annual off-site population dose-risk of 7.11 person-rem per year. The calculated value for C using 20 years and a 3 percent discount rate is approximately 15.04. Therefore, calculating the discounted monetary equivalent of accident dose-risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value (15.04). The calculated off-site exposure cost is $213,863.

F.4.2 OFF-SITE ECONOMIC COST RISK

The Level 3 analysis showed an annual off-site economic risk of $53,358. Calculated values for off-site economic costs caused by severe accidents must also be discounted to present value. This is performed in the same manner as for public health risks and uses the same C value. The resulting value is $802,484.

F.4.3 ON-SITE EXPOSURE COST RISK

Occupational health was evaluated using the NRC-recommended methodology that involves separately evaluating immediate and long-term doses (NRC 1997).

For immediate dose, the NRC recommends using the following equation:

Equation 1:

$$WIO = R\{(FDIO)S - (FDIO)A\} \{[1 - \exp(-rtf)]/r\}$$

Where:

W_{IO}	=	monetary value of accident risk avoided due to immediate doses, after discounting
R	=	monetary equivalent of unit dose ($2,000 per person-rem)
F	=	accident frequency (events per year) (2.58E-06 (internal events CDF)) at an average 1E-12/yr truncation
D_{IO}	=	immediate occupational dose [3,300 person-rem per accident (NRC estimate)]
$_S$	=	subscript denoting status quo (current conditions)
$_A$	=	subscript denoting after implementation of proposed action
r	=	real discount rate (0.03 per year)

t_f = years remaining until end of facility life (20 years).

Assuming FA is zero, the best estimate of the immediate dose cost is:

$$W_{IO} = R\,(FD_{IO})_S\,\{[1 - \exp(-rt_f)]/r\}$$
$$= 2{,}000 * 2.58E\text{-}06 * 3{,}300 * \{[1 - \exp(-0.03 * 20)]/0.03\}$$
$$= \$256$$

For long-term dose, the NRC recommends using the following equation:

Equation 2:

$$WLTO = R\{(FDLTO)S - (FDLTO)A\}\,\{[1 - \exp(-rtf)]/r\}\{[1 - \exp(-rm)]/rm\}$$

Where:

W_{LTO} = monetary value of accident risk avoided long-term doses, after discounting, $

D_{LTO} = long-term dose [20,000 person-rem per accident (NRC estimate)]

m = years over which long-term doses accrue (as long as 10 years)

Using values defined for immediate dose and assuming FA is zero, the best estimate of the long-term dose is:

$$W_{LTO} = R\,(FD_{LTO})_S\,\{[1 - \exp(-rt_f)]/r\}\,\{[1 - \exp(-rm)]/rm\}$$
$$= 2{,}000 * 2.58E\text{-}06 * 20{,}000 * \{[1 - \exp(-0.03 * 20)]/0.03\}\,\{[1 - \exp(-0.03 * 10)]/0.03 * 10\}$$
$$= \$1{,}341$$

The total occupational exposure is then calculated by combining Equations 1 and 2 above. The total accident related on-site (occupational) exposure risk (W_O) is:

$$WO = WIO + WLTO = (\$256 + \$1{,}341) = \$1{,}597$$

F.4.4 ON-SITE CLEANUP AND DECONTAMINATION COST

The total undiscounted cost of a single event in constant year dollars (C_{CD}) that NRC provides for cleanup and decontamination is $1.5 billion (NRC 1997). The net present value of a single event is calculated as follows. NRC uses the following equation to integrate the net present value over the average number of remaining service years:

$$PV_{CD} = [C_{CD}/mr][1\text{-}\exp(-rm)]$$

Where:

PV_{CD} = net present value of a single event

C_{CD} = total undiscounted cost for a single accident in constant dollar years

r = real discount rate (0.03)

m = years required to return site to a pre-accident state

The resulting net present value of a single event is $1.3E+09. The NRC uses the following equation to integrate the net present value over the average number of remaining service years:

$$U_{CD} = [PV_{CD}/r][1\text{-}\exp(-rt_f)]$$

Where:

PV_{CD} = net present value of a single event ($1.3E+09)

r = real discount rate (0.03)

t_f = 20 years (license renewal period)

The resulting net present value of cleanup integrated over the license renewal term, $1.95E+10, must be multiplied by the internal events CDF (2.58E-06) to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent is $50,284.

F.4.5 REPLACEMENT POWER COST

Long-term replacement power costs were determined following the methodology documented in NUREG/BR-0184 (NRC 1997). The net present value of replacement power for a single event, PV_{RP}, was determined using the following equation:

$$PV_{RP} = [\$1.2\times10^8/r] * [1 - \exp(-rt_f)]^2$$

Where:

PV_{RP} = net present value of replacement power for a single event, ($)

r = 0.03

t_f = 20 years (license renewal period)

To attain a summation of the single-event costs over the entire license renewal period, the following equation is used:

$$U_{RP} = [PV_{RP} / r] * [1 - \exp(-rt_f)]^2$$

Where:

U_{RP} = net present value of replacement power over life of facility ($-year)

After applying a correction factor to account for LSCS's size relative to the "generic" reactor described in NUREG/BR-0184 (NRC 1997) (i.e., 1210 megawatt electric / 910 megawatt electric), the replacement power costs are determined to be 7.35E+09 ($-year). Multiplying 7.35E+09 ($-year) by the CDF (2.58E-06) results in a replacement power cost of $18,955.

F.4.6 MAXIMUM AVERTED COST-RISK

The LSCS MACR is the total averted cost-risk if all internal and external events risks associated with on-line operation were eliminated. This is calculated by summing the following components:

- Maximum Internal Events Averted Cost-Risk
- Maximum External Events Averted Cost-Risk

The MACR is used in the Phase I analysis as a means of screening SAMAs. The following subsections provide a description of how each of these components is calculated and used together to obtain the LSCS MACR.

F.4.6.1 INTERNAL EVENTS MAXIMUM AVERTED COST-RISK

The maximum internal events averted cost-risk is the sum of the contributors calculated in Sections F.4.1 through F.4.5:

Maximum Averted Internal Events Cost-Risk

Off-site exposure cost	$213,863
Off-site economic cost	$802,484
On-site exposure cost	$1,597
On-site cleanup cost	$50,284
Replacement power cost	$18,955
Total cost (per unit)	$1,087,183

This total represents the per unit monetary equivalent of the risk that could be eliminated if all risk associated with on-line internal event hazards (including internal floods) could be eliminated for LSCS. The internal events MACR is rounded to next highest thousand ($1,088,000) for SAMA calculations. It should be noted that the Phase II cost benefit calculations account for the difference between the rounded MACR and the actual MACR by adding the difference to the averted cost-risk calculated for each SAMA.

F.4.6.2 EXTERNAL EVENTS MAXIMUM AVERTED COST-RISK

The maximum averted cost-risk for external events must be quantified for the cost-benefit calculations; however, this cost-risk must be estimated based on information in the RMIEP (NRC 1992b, NRC 1993) and IPEEE analyses (CECo 1994) given that complete, current, external events models are not available for LSCS (with the exception of the interim fire model, which is discussed further in section F.5.1.6.1). An update of the fire model will be performed in the future and a seismic model update is in progress, but those models are not developed to the point where they can be used for quantitative or qualitative input to the SAMA analysis. As a result, an alternate method of accounting for the external events contributions must be established.

The method chosen to account for external events contributions in the SAMA analysis is to use a multiplier on the internal events results. In previous NRC-approved SAMA analyses, it has been assumed that the risk posed by external events and internal events is approximately equal. This assumption is not unreasonable unless available analyses indicate that there are external events contributors that present a disproportionate risk to the site. Based on the magnitude of the LSCS fire CDF relative to the internal events CDF, it was concluded that the development of an external events multiplier was warranted.

The external events multiplier is the ratio of the total CDF (including internal and external events) to only the internal events CDF. The lack of detailed analyses makes it difficult to establish a meaningful CDF for some event types; however, some assumptions can be made about the non-quantified initiator groups that can be used to develop a total external events CDF. Estimates for each of the non-screened external events hazards were developed for use in the calculation of the external events multiplier. Because the LSCS IPEEE essentially reproduces what was reported in the RMIEP analysis for external events, the RMIEP analysis was used as the source for most of the information used to establish CDFs for the non-screened external events contributors. The contributors included are seismic, fire, turbine generated missiles, accidental aircraft impact, high winds, transportation and nearby facility accidents, and external flooding. A description of the CDF used in the development of the external events multiplier is provided below.

Seismic CDF: The seismic model that was developed as part of the RMIEP analysis in 1993 estimated a seismic CDF of 6.0E-07/yr, which accounted for 20 different accident sequences over a range of six seismic intervals. The RMIEP model was not maintained with the internal events PRA and the development of the LSCS seismic PRA is not yet complete; therefore, the RMIEP analysis represent the latest official assessment of seismic risk for LSCS. While the LSCS seismic PRA has not been developed to a stage where CDF results are available to support the SAMA analysis, the seismic hazard curves are available. Because the RMIEP documentation provides sequence specific conditional core damage probabilities, it was possible to update the RMIEP seismic CDF using the current LSCS seismic hazard curves, as described in section F.5.1.6.2. While there are limitations associated with this process, it is considered to represent a reasonable approach to estimating how the RMEIP results would be impacted by current seismic hazard information. The “updated” RMIEP seismic CDF of 6.6E-07/yr is used to here to develop the external events multiplier.

Fire CDF: The latest available fire results are from the LSCS Revision 1 fire model (Exelon 2009). While this model was completed in 2009, it is considered to be an interim model because there are portions of the NUREG/CR-6850 methodology (EPRI 2005) that have not yet been implemented. For the purposes of establishing the LSCS SAMA external events multiplier, the Revision 1 fire model CDF of 9.41E-06/yr is used.

Turbine Generated Missiles: A bounding analysis was performed in RMIEP to assess the risk associated with turbine generated missiles. The mean CDF was estimated to be 9.50E-08/yr, which is used to establish LSCS SAMA external events multiplier.

Accidental Aircraft Impact: A bounding analysis was performed in RMIEP to assess the risk associated with accidental aircraft impact. A median CDF of 5.0E-07/yr is documented in the analysis, but a mean CDF is not explicitly provided. For the purposes of establishing the LSCS SAMA external events multiplier, the mean was assumed to be approximated by the median and a CDF of 5.0E-07/yr was used for this contributor.

High Wind Events: A bounding analysis was performed in RMIEP to assess the risk associated with high wind events. A median CDF of 3.0E-08/yr is documented in the analysis, but a mean CDF is not explicitly provided. For the purposes of establishing the LSCS SAMA external events multiplier, the mean was assumed to be approximated by the median and a CDF of 3.0E-08/yr was used for this contributor.

Transportation and Nearby Facility Accidents: A bounding analysis was performed in RMIEP to assess the risk associated with transportation and nearby facility accidents. The conclusion of the analysis was that these types of events are not significant contributors to plant risk and a CDF was not explicitly developed as part of the analysis. The implication is that while transportation and nearby facility accidents are relevant to the plant, they are negligible contributors to risk and do not need to be included in the external events CDF used to develop the external events multiplier. A more conservative approach is taken here, however, which is to assume the risk associated with transportation and nearby facility accidents is equal to that of the lowest quantified external event CDF (3.0E-08/yr for high wind events). For the purposes of establishing the LSCS SAMA external events multiplier, a CDF of 3.0E-08/yr was used for this contributor.

External Flooding: A bounding analysis was performed in RMIEP to assess the risk associated with external flooding events. The conclusion of the analysis was that these types of events are not significant contributors to plant risk and a CDF was not explicitly developed as part of the analysis. The implication is that while external flooding events are relevant to the plant, they are negligible contributors to risk and need not be included in the external events CDF used to develop the external events multiplier. A more conservative approach is taken here, however, which is to assume the risk associated with external flooding events is equal to that of the lowest quantified external event CDF (3.0E-08/yr for high wind events). For the purposes of establishing the LSCS SAMA external events multiplier, a CDF of 3.0E-08/yr was used for this contributor.

Using the CDF values described above, the external events (EE) contributions could be summarized as follows:

LSCS External Events CDF Summary (per year)

Fire	9.41E-06
Seismic	6.60E-07
Turbine Generated Missiles	9.50E-08
Accidental Aircraft Impact	5.00E-07
High Winds	3.00E-08
Transportation & Nearby Facility Accidents	3.00E-08
External Flooding	3.00E-08
Total EE CDF	**1.08E-05**

The External Events multiplier is the ratio of the total CDF (including internal and external events) to the internal events CDF. Using the total external events of 1.08E-05 from above and the Unit 2 internal events CDF of 2.58E-06, the External Events multiplier is:

EE Multiplier = (2.58E-06 + 1.08E-05) / 2.58E-06 = 5.2

F.4.6.3 LSCS MAXIMUM AVERTED COST-RISK

The total MACR can be obtained by multiplying the internal events cost-risk by the EE multiplier of 5.2:

Single Unit MACR = $1,088,000 * 5.2 = $5,657,600

Alternatively, as stated in Section F.4.6, the MACR can be represented by the internal and external events contributions:

Internal Events	=	$1,088,000
External Events	=	$4,569,600
Single Unit Maximum Averted Cost-Risk	=	$5,657,600

The MACR and implementation costs are considered on a per-unit scale for consistency (unless otherwise noted).

F.5 PHASE 1 SAMA ANALYSIS

The Phase 1 SAMA analysis, as discussed in Section F.1, includes the development of the initial SAMA list and a coarse screening process. This screening process eliminated those candidates that are not applicable to the plant's design or are too expensive to be cost-beneficial even if the risk of on-line operations were completely eliminated (i.e., the implementation costs exceed the MACR). The following subsections provide additional details of the Phase 1 process.

F.5.1 SAMA IDENTIFICATION

The initial list of SAMA candidates for LSCS was developed from a combination of resources. These include the following:

- LSCS PRA results and PRA Group Insights

- Industry Phase 2 SAMAs (based on a review of potentially cost-effective Phase 2 SAMAs from selected plants, as documented in section F.5.1.3)
- LSCS Individual Plant Examination IPE (ComEd 1994)
- LSCS IPEEE (ComEd 1997b)

These resources are judged to provide a list of potential plant changes that are most likely to reduce risk in a cost-effective manner for LSCS.

In addition to the "Industry Phase 2 SAMA" review identified above, an industry based SAMA list was used in a different way to aid in the development of the LSCS plant-specific SAMA list. While the industry Phase 2 SAMA review cited above was used to identify potential SAMAs from specific sites that might have been overlooked in the development of the LSCS SAMA list due to PRA modeling issues, a generic SAMA list was used to help identify the types of changes that could be used to address the areas of concern identified through the LSCS importance list review. For example, if Instrument Air (IA) availability was determined to be an important issue for LSCS, the industry list would be reviewed to determine if a plant enhancement had already been identified that would address LSCS's needs. If an appropriate SAMA was found to exist, it would be used in the LSCS list to address the IA issue; otherwise, a new SAMA would be developed that would meet the site's needs. This generic list was compiled as part of the development of multiple industry SAMA analyses and is available in NEI 05-01 (NEI 2005).

It should be noted that the process used to identify LSCS SAMA candidates focuses on plant-specific characteristics and is intended to address only those issues important to the site. An evaluation of the generic SAMAs in NEI 05-01, as they are written, provides little benefit because in most cases the systems are not exactly the same as those at LSCS. Without modifying the NEI 05-01 SAMAs to match the systems at LSCS, many would be screened as "not applicable". Further, the scopes of the generic SAMAs are not tailored to match the needs of a specific plant such, that the generic SAMAs may address only a fraction of the required functions. As a result, evaluation of the entire generic SAMA list would only be useful after each SAMA has been modified to address the plant specific risk profile. The processes used for LSCS were more efficient than evaluating the entire generic SAMA list as written.

F.5.1.1 LEVEL 1 LSCS IMPORTANCE LIST AND RISK CONTRIBUTOR REVIEW

The importance list review was performed to identify the failure scenarios most important to the LSCS risk profile and to develop methods to mitigate those scenarios. For each event on the importance list, the reasons for the event's importance are determined through sequence/cutset and systems analysis. Strategies to mitigate the relevant failures are developed based on accident sequence review, plant knowledge, and industry insights. For LSCS, importance lists were developed and reviewed for the internal events model. For the fire model, the top contributing fire zone results were reviewed to identify SAMAs.

The importance list itself was developed from the LSCS PRA cutsets and comprises the model's basic events sorted according to their risk reduction worth (RRW) values. The events with the largest RRW values in this list are those events that would provide the greatest reduction in the CDF if the failure probability were set to zero. Because a PRA's importance list can be extensive, it is desirable to limit the review to only those contributors that could yield potentially cost-beneficial results.

One method that can be used to limit the scope of the importance list review is to correlate the RRW value threshold to the lowest expected cost of implementation for a SAMA. Usually, operator action modifications in the form of procedure changes are among the least expensive enhancements that can be made at a site, so they have often been used as the representative "lowest cost SAMA". However, because the cost of performing a procedure change can vary by orders of magnitude depending on the scope of the change and the procedure that is being changed, this does not provide a clear basis for a review threshold. In addition, the use of this type of a threshold can lead to a review process that is beyond the scope of what is described in NEI 05-01 (NEI 2005).

The NEI 05-01 guidance describes the SAMA identification process in Section 5.1 as a process to "identify plant-specific SAMA candidates by reviewing dominant risk contributors (to both CDF and population dose) in the Level 1 and Level 2 Probabilistic Safety Assessment (PSA) models." Section 5.1 indicates that the definition of the dominant contributors is open to interpretation, but the guidance does not imply that the identification process should represent an exhaustive search for all plant enhancements that could be cost-beneficial. For example, some minor plant procedure changes could be very inexpensive, but the SAMA identification process should not be defined as one that requires a review all events that could yield averted cost-risks that are greater than the cost of such a procedure change.

Because there is not a universal definition for "dominant risk contributors", an attempt has been made in this analysis to characterize "dominant contributors" and to establish a review threshold that can reasonably be considered to address them.

The ASME/ANS PRA Standard (ASME 2009) includes a definition of "significant" contributors to risk, but it is described in quantitative terms related to the percentages of risk represented, and the guidance does not provide many qualitative insights about the nature of "significant contributors". In general, the term "dominant" suggests something that is ruling, governing, or in a commanding position, which does not appear to be consistent with a "risk significant" basic event or accident sequence. For example, a risk significant basic event is one with a Fussell-Vesely (FV) value of 0.005 or greater, which corresponds to an event that would reduce the CDF by 0.5% if it were made completely reliable. Events contributing only 0.5% to the CDF could not reasonably be described as "governing" or "ruling" the risk profile.

For the SAMA analysis, the threshold of a dominant basic event is considered to be a factor of 10 larger than for a risk significant event. Similarly, the threshold for a dominant individual accident sequence is considered to be an order of magnitude large than the value of 1% defined in the ASME/ANS PRA Standard for risk significant accident sequences. The definitions of the "dominant" basic events and accident sequences are assumed to be:

- Dominant Basic Events are those events with FV values greater than or equal to 0.05 (or Risk Reduction Worth values of about 1.05 or greater) for the relevant figure of merit (e.g., CDF).
- Dominant Individual Accident Sequences are those which contribute 10 percent or more to the relevant figure of merit (e.g., CDF).

A complicating factor is that the level of detail and maturity of the risk assessments for different hazard groups are not necessarily consistent. In order to address this issue, the review thresholds are applied to the individual contributors rather than to the overall CDF.

For the internal events analysis, there are about 50 events with RRW values greater than 1.05, and these are considered to represent the dominant basic events for LSCS. However, events with RRW values of 1.01 or greater were reviewed as part of the analysis and the results have been included to make the review more robust. Table F.5-1a documents the disposition of each basic event in the Level 1 internal events model with an RRW value of 1.01 or greater. When the impact on external events is considered, this corresponds to an event that would reduce the cost-risk by about $56,000 if it were made completely reliable. Viewed from another perspective, a RRW value of 1.01 corresponds to a CDF reduction of about 1% assuming the basic event failure probability were set to zero. For a nominal 2.58E-6 /yr CDF from internal events, this corresponds to a potential CDF reduction of about 3E-8 /yr. Such a change in CDF is well below the widely accepted threshold in Region III of Figure 4 in Regulatory Guide 1.174 (USNRC 2011) of what constitutes a "very small change" (less than 1E-6 /yr).

The review of the fire model was performed on a fire zone level due to the similarity in the impact of the fires and the potential means that might be available to mitigate them. The fire CDF, based on the current LSCS Fire PRA (Exelon 2009), is 9.41E-06. If fire zones are equated to accident sequences, it would be necessary to review all fire zones with CDFs of 9.41E-07 or greater. This approach would include two fire zones from each unit. However, because fire zones and accident sequences are not equivalent, the review threshold has been reduced by a factor of two in order to capture a larger portion of the LSCS fire contributors (i.e., all fire zones contributing 5% or more to the fire CDF). If it is assumed that the ratio of internal events cost-risk to internal events CDF is equal to the ratio of fire cost-risk to fire CDF, the fire zone review threshold would correspond to about $198,000. The next largest un-reviewed fire zone is Unit 1 Zone 2F-2 at 3.36E-07/yr, which corresponds to a potential averted cost-risk of about $142,000.

For LSCS, the seismic risk is concentrated in a relatively few number of sequences. Over 88% of the risk is associated with the three accident sequences that meet the definition of a dominant accident sequence. However, because the RMIEP documentation includes a description of the Small-LOCA-3 accident sequence (5.6% of the updated seismic CDF), this sequence was included in the SAMA identification process due to ease of review. The next largest un-reviewed seismic accident sequence is Small-LOCA-4 at 2.50E-8/yr, which corresponds to a potential averted cost-risk of about $11,000.

The remaining external events contributors, such as high winds, were treated with bounding analyses in the RMIEP evaluation and limited information was available related to specific risk contributors for these types of events. The RMIEP documentation was reviewed to identify any SAMAs could reduce the risk associated with these events, as documented in sections F.5.1.6.3 through F.5.1.6.7.

F.5.1.2 LEVEL 2 LSCS IMPORTANCE LIST REVIEW

The review of the Level 2 importance listings was performed in a manner similar to that which was performed for the Level 1 importance list. In this case, three separate Level 2 importance lists were developed. The reviews were performed on composite importance files for the following release categories:

- High (H/E-BOC, H/E, H/I)
- Medium Early (ME)
- Medium Intermediate (MI)

These groupings were developed to prevent high frequency-low consequence events (i.e., the L/E release category) from biasing the importance lists. The release categories included in the review account for over 97 percent of the dose-risk while accounting for only about 55 percent of the Level 2 frequency. Exclusion of the other results from the Level 2 review allows the contributors that are most important to dose-risk and cost-risk to rise to the top of the importance lists.

For the importance groups defined above, the number of “dominant” basic events (RRW > 1.05) ranges from about 45 to 60 events. While a review of this group of events is considered to meet the intent of NEI 05-01, the review was expanded to include all events with RRW values of 1.03 or greater. If a basic event had and RRW value of just under 1.03 on the Level 1 importance list and all three Level 2 importance lists, the potential averted cost-risk associated with the event would be about $165,000 when the external events multiplier is applied.

None of the external events models are linked to the Level 2 model; therefore, it was not possible to perform a Level 2 importance review for the external events hazards.

Tables F.5-2a, F.5-2b, and F.5-2c document the disposition of each basic event in the Level 2 RRW lists with RRW values greater than 1.03.

F.5.1.3 INDUSTRY SAMA REVIEW

The SAMA identification process for LSCS is primarily based on the PRA importance listings, the IPE, and the IPEEE. Use of these sources should identify the types of changes that would most likely be potentially cost-beneficial for LSCS; however, a review of those SAMAs determined to be cost-beneficial for similar plants could capture potentially important changes not identified for LSCS due to PRA modeling differences or because an alternate approach was developed to mitigate a similar risk. Therefore, in addition to the plant-specific review, selected industry SAMA submittals and the NRC's associated Generic Environmental Impact Statement (NUREG-1437) supplement documents were reviewed to identify any SAMA candidates that were determined to be potentially cost-beneficial. These SAMAs were further analyzed and included in the LSCS SAMA list if they were considered to address potential risks not identified by the LSCS importance list review.

The following six BWRs were used as the sources for the SAMAs:

- Susquehanna Steam Electric Station (PPL 2006, NRC 2009)
- Cooper Nuclear Station (NPPD 2008, NRC 2010a)
- Duane Arnold Energy Center (FPL 2008, NRC 2010b)
- Nine Mile Point, Unit 2 (CEG 2004, NRC 2006)
- Columbia Generating Station (ENW 2010, NRC 2012a)
- Grand Gulf Nuclear Station (Entergy 2011, NRC 2013a)

The cost-beneficial SAMAs from each of these sites are reviewed in the following subsections.

F.5.1.3.1 Susquehanna Steam Electric Station (SSES)

Susquehanna identified two SAMAs in the baseline analysis that were determined to be potentially cost-beneficial and three additional SAMAs were identified as potentially cost-beneficial in the 95th percentile PRA results sensitivity analysis.

Review of Susquehanna Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
2a	Improve Cross-Tie Capability Between 4kV AC Emergency Buses (A-D, B-C)	SSES did not credit cross-tie between EDG trains and relied on the swing EDG to mitigate EDG failures. For LSCS, the bus configuration is not the same. Division I and II inter-unit cross-ties are available as well as power alignments between the ESF and non-ESF 4kV buses in the same division, but a potential improvement would be to provide an inter-division cross-tie capability (e.g., 241Y to 242Y) (SAMA 24). Division III power failures are relatively small contributors to risk and providing the additional capability of a division III inter-unit cross-tie would not be cost beneficial.	Added to SAMA list (SAMA 24).

Review of Susquehanna Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
6	Procure Spare 480V AC Portable Station Generator	This SAMA is not applicable to a plant without an existing 480V AC generator, but a SAMA to improve the availability of 480V AC power was developed for LSCS based on the review of the PRA results (SAMA 8). Installation of a 480V AC generator will mitigate most of the risk associated with the unavailability of 480V AC power.	Functional Equivalent Already Included on the SAMA list; Industry SAMA not added.
2b	Improve Cross-Tie Capability Between 4kV AC Emergency Buses (A-BC-D)	This SAMA is an enhancement over SSES SAMA 2a and allows cross-tie between any EDG division. For LSCS, the bus configuration is not the same. Inter-unit cross-ties are available as well as power alignments between the ESF and non-ESF 4kV buses in the same division, but a potential improvement would be to provide an inter-division cross-tie capability (e.g., 241Y to 242Y) (SAMA 24).	Added to SAMA list (SAMA 24).
3	Proceduralize Staggered RPV Depressurization When Fire Protection System Injection is the Only Available Makeup Source	This SAMA is specific to the SSES site and is based on the need to split flow from a single injection system between units. The same type of fire protection system flow limitations do not exist for LSCS and this SAMA is not applicable to the LSCS design.	Not required on SAMA list.
5	Auto Align 480V AC Portable Station Generator	This SAMA is not applicable to a plant without an existing 480V AC generator, but a SAMA to improve the availability of 480V AC power was developed for LSCS based on the review of the PRA results (SAMA 8). Installation of a 480V AC generator will mitigate most of the risk associated with the unavailability of 480V AC power.	Functional Equivalent Already Included on the SAMA list; Industry SAMA not added.

F.5.1.3.2 Cooper Nuclear Station

Cooper identified eight SAMAs in the baseline analysis that were determined to be potentially cost-beneficial, and three additional SAMAs were identified as potentially cost-beneficial in the 95th percentile PRA results sensitivity analysis.

Review of Cooper Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
14	Portable generator for DC power to supply the individual panels.	This SAMA was designed to allow High Pressure Coolant Injection operation after battery depletion. A similalr SAMA was developed for LSCS to address RCIC and SRV operation (SAMA 14).	Already included.
25	Revise procedure to allow bypass of RCIC turbine exhaust pressure trip	Allows RCIC to operate when suppression pool pressures are high enough to trip the RCIC turbine on high turbine exhaust pressure. The LSCS backpressure trip is relatively high and is not limiting for the current configuration. The backpressure trip could be bypassed in conjunction with modification of procedures to manage HCTL issues, but this would be used in post battery depletion periods in SBO scenarios where it would be required to controling RCIC without DC power. A more reliable means of mitigating long term SBOs is considered to be fire protection injection via SAMAs 1 and 8 (which would also provide instrumentation power). This SAMA is addressed by other means for LSCS.	Functional Equivalent Already Included on the SAMA list; Industry SAMA not added.
78	Improve training on alternate injection via FPS	The intent of this SAMA is to improve the reliability of the operator action to align alternate injection with the fire protection system, but the SAMA does not identify what problems exist with the current training program, what credible changes could be made to measurably improve reliability, or how any such changes would impact the HRA assessment. SAMA 18 was developed for LSCS based on an assessment of the PRA results and the existing fire protection injection capabilities.	Functional Equivalent Already Included on the SAMA list; Industry SAMA not added.
30	Revise procedures to allow manual alignment of the fire water system to RHR heat exchangers	This SAMA was designed to mitigate loss of SW cooling to the RHR heat exchangers. Loss of cooling to the RHR heat exchangers can occur at LSCS, but the important contributors are related to loss of room cooling for the Core Standby Cooling System vaults. For LSCS, a lower cost alternative that addresses these failures is considered to be SAMA 16.	Functional Equivalent Already Included on the SAMA list; Industry SAMA not added.

Review of Cooper Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
68	Proceduralize the ability to cross connect the circulating water pumps and the service water going to the TEC heat exchangers	This SAMA is designed to provide an alternate cooling medium to the closed loop cooling system that cools the turbine building loads for Cooper. For LSCS, the service water system ultimately provides cooling to the turbine building closed loop cooling system. Service water does have an existing cross-tie to the fire protection system, but its intent is for service water to serve as an alternate supply to the fire protection system and there are check valves installed to prevent flow from the fire protection system to the service water system. This SAMA is not applicable to LSCS because it is not possible to provide an alternate water supply to the turbine building closed loop cooling system with only a procedure change (hardware changes would also be necessary).	Not required on SAMA list.
33	Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	This SAMA appears to be aimed at providing a long term supply of water to FW/Condensate. LSCS currently has the capability to provide makeup to the CST via several methods (e.g., using the fire protection system), which ultimatley supports hotwell makeup for FW/Condensate. This SAMA is considered to already be implemented at LSCS.	Not required on SAMA list.
40	Operator procedure revisions to provide additional space cooling to the EDG room via the use of portable equipment	For LSCS, the primary causes of room cooling failures for the EDGs are related to the loss of the room cooling for the EDG cooling water pumps. A similar SAMA was developed for LSCS to address these failures (SAMA 16).	Already included.
45	Provide an alternate means of supplying the instrument air header	This SAMA is intended to improve the reliability of the Instrument Air system by providing an alternate supply to the system header. LSCS has a trailer mounted air compressor that can be used to supply the instrument air system and this SAMA is considered to already be implemented at LSCS.	Not required on SAMA list.
64	Proceduralize the use of a fire pumper truck to pressurize the fire water system	Fire water reliability can be enhanced by proceduralizing the use of a fire truck to pressurize the fire water header. LSCS already has a procedure for this capability and this SAMA is considered to already be implemented at LSCS.	Not required on SAMA list.

Review of Cooper Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
75	Generation Risk Assessment implementation into plant activities	The intent of this SAMA appears to be the incorporation of risk management tools into work planning practices. This is already performed at LSCS.	Not required on SAMA list.
79	Modify procedures to allow use of the RHRSW system without a SWBP	Not applicable to LSCS; the service water system already operates without booster pumps for system cooling.	Not required on SAMA list.

F.5.1.3.3 Duane Arnold Energy Center

Duane Arnold identified two SAMAs in the baseline analysis that were determined to be potentially cost-beneficial and one additional SAMA was identified as potentially cost-beneficial in the uncertainty analysis.

Review of Duane Arnold Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
117	Increase boron concentration or enrichment in the standby liquid control system.	The LSCS design already uses an enriched boron solution that allows operation of a single standby liquid control pump to meet the requirements of 10CFR50.62. Further enriching the boron solution could potentially increase the time available to inject boron, but this would have a minimal impact on risk. Level control and boron injection are both required to limit the heat load to containment in ATWS events and the cues are essentially the same for both actions (very high dependence between actions). Providing margin for boron injection initiaton would not provide significant benefit if level control is delayed because the early heat load to the containment would be higher. Other SAMAs related to ATWS mitigation have been identified that are considered to be more effective means of reducing the risk of these scenarios (e.g. SAMAs 4 and 5) and further enriching boron is not suggested as a SAMA for LSCS.	Functional Equivalent Already Included on the SAMA list; Industry SAMA not added.
156	Provide an alternate source of	This SAMA addresses clogging of flow to the RHRSW/ESW pump intake area. This was	Not required on SAMA list.

Review of Duane Arnold Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
	water for the RHRSW/ESW pit.	addressed at DAEC by assuming that a cross connect could be added to allow communication between the Circ Water and RHRSW/ESW pits. LSCS has a bypass line around the normal intake route to ensure that a continuous water supply is available to the water tunnel should the travelling screens become blocked. The bypass line is considered to meet the intent of this SAMA and this SAMA is considered to already be implemented for LSCS.	
166	Increase the reliability of the low pressure ECCS RPV low pressure permissive circuitry. Install manual bypass of low pressure permissive	The intent of this SAMA is to reduce the probability that low pressure injection will be failed by the low pressure permissive sensors or logic. The low pressure permissive is modeled for LSCS, but it is not a risk significant contributor and this type of enhancement would not be cost-beneficial for LSCS.	Not required on SAMA list.

F.5.1.3.4 Nine Mile Point, Unit 2

Review of Nine Mile Point, Unit 2 Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
U2-23a	Provide redundant ventilation for residual heat removal (RHR) pump rooms	A similar SAMA was developed based on the review of the LSCS PRA results (SAMA 16).	Already included.
U2-23b	Provide redundant ventilation for high pressure core spray (HPCS) pump room	For LSCS, the HPCS room cooling function is not risk significant, but SAMA 16 could also be used for alternate HPCS room cooling, if required.	Already included.
U2-23c	Provide redundant ventilation for reactor core isolation cooling (RCIC) pump room	For LSCS, RCIC does not require room cooling for the 24 hour mission time and this SAMA would not be a cost-beneficial change.	Not required on SAMA list.

Review of Nine Mile Point, Unit 2 Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
U2-213	Enhance loss of service water procedure	For NMP-2, the loss of service water is related to the loss of room cooling for the RHR, HPCS, and RCIC systems and actions to perform alternate room cooling alignments were expected to be integrated with the loss of service water procedure. LSCS SAMA 16 is considered to include the development of any procedure links required to use the equipment. The other issue for NMP-2 appears to be related to enhancing loss of SW procedure so that it addresses the dominate failures identified in the PRA. The LSCS service water system design is different than for NMP-2 and the loss of service water initiating event is below the SAMA review threshold. No additional SAMAs are considered to be required to address loss of service water at LSCS.	Already included.
U2-214	Enhance Station Blackout procedures	This SAMA was developed for NMP-2 to address plant specific procedure deficiencies for certain plant configurations, which at the time of the analysis, were addressed by compensatory measures. This is not expected to be applicable to the LSCS electric power configuration. In addition, LSCS constantly assesses and improves plant procedures as part of normal operations and the general intent of this SAMA is considered to be met for LSCS.	Not required on SAMA list.
U2-215	Use of a portable charger for the batteries	A similar SAMA was developed based on the review of the LSCS PRA results (SAMA 8).	Already included.
U2-216	Hard pipe diesel fire pump to the reactor pressure vessel	A similar SAMA was developed based on the review of the LSCS PRA results (SAMA 18). For LSCS, a hard pipe connection is suggested apart from a short, flexible connecting hose to help maintain a separation between the RCS inventory and the lake water in the fire protection system.	Already included.
U2-221a	Reduce unit cooler contribution to emergency diesel generator (EDG) unavailability by increasing the testing frequency	The DG cooling water pumps and fans have high availability and availability is managed through the work control and maintenance rule programs. No opportunities for improvement in availability were identified in either the test frequencies or maintenance practices.	Not required on SAMA list.

Review of Nine Mile Point, Unit 2 Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
U2-221b	Reduce unit cooler contribution to EDG unavailability by providing redundant means of cooling	The redundant means of cooling represented by this SAMA is to open the EDG control panel room doors. For LSCS, the primary causes of room cooling failures for the EDGs are related to the loss of the room cooling for the EDG cooling water pumps. A similar SAMA was developed for LSCS to address these failures (SAMA 16).	Already included.
U2-222	Improve procedure for loss of instrument air	For NMP-2, the suggested loss of IA procedure enhancements would help maintain feedwater by including steps to isolate the min flow lines back to the condenser. For LSCS, the loss of instrument air procedure already includes the steps to isolate the min flow lines.	Not required on SAMA list.
U2-223	Improve control building flooding scenarios	The NMP-2 SAMA does not provide specific procedure enhancements and includes only general suggestions to move a firewater header or to install doors that would prevent water accumulation. For LSCS, the significant flooding contributors are addressed in the importance list review and SAMAs were developed to address these events (e.g., SAMAs 9 and 11).	Functional Equivalent Already Included on the SAMA list; Industry SAMA not added.

F.5.1.3.5 Columbia Generating Station

Review of Columbia Generating Station Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
AC/DC-28	Reduce common cause failures (CCFs) between EDG-3 and EDG-1/2	The description of the Columbia SAMA is to reduce CCF by providing separate fuel supplies, separate maintenance crews, and diverse instrumentation. For LSCS, EDG CCF events are below the review threshold and the EDGs already have some elements of the Columbia SAMA, including separate instrumentation panels and EDG specific fuel tanks/fuel transfer systems. Because the EDGs are otherwise of the same design, efforts to further differentiate the EDGs would not provide a sufficient basis for excluding or reducing the CCF probabilities and no measurable benefit would be expected from this SAMA.	Not required on SAMA list.

Review of Columbia Generating Station Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
CC-03b	Raise RCIC backpressure trip set points	Allows RCIC to operate when suppression pool pressures are high enough to trip the RCIC turbine on high turbine exhaust pressure. The LSCS backpressure trip is relatively high and is not limiting for the current configuration. The backpressure trip could be bypassed in conjunction with modification of precedures to manage HCTL issues, but this would be used in post battery depletion periods in SBO scenarios where it would be required to controling RCIC without DC power. A more reliable means of mitigating long term SBOs is considered to be fire protection injection via SAMAs 1 and 8 (which would also provide instrumentation power). Thus, this SAMA is addressed by other means for LSCS.	Functional Equivalent Already Included on the SAMA list; Industry SAMA not added.
FR-07a	Improve the fire resistance of critical cables for containment venting	The reliable hard pipe containment vent (SAMA 1) will allow LSCS to vent without support systems and is considered to address the intent of this SAMA.	Functional Equivalent Already Included on the SAMA list; Industry SAMA not added.
FR-07b	Improve the fire resistance of critical cables for transformer E-TR-S	The equivalent transformer for LSCS may be the Unit SATs, which are failed in some essential switchgear room fires. In most cases, one or more diesel generators from the same unit would be available to provide power, which could be accomplished by allowing inter-division cross-tie. While it may be possible to protect the cables associated with the Unit SATs, a lower cost approach to providing power is considered to be through the implementation of inter-division 4kV AC cross-ties, which was identified in the internal events review.	Functional Equivalent Already Included on the SAMA list; Industry SAMA not added.
FR-08	Improve the fire resistance of cables to RHR and standby SW	For LSCS, many of the dominant fires that impact RHR are those for which failure of the ignition source fails RHR. In such cases, there is no opportunity to protect the RHR system through the use of fire barriers or cable wrap. For the remaining cases, implementation of SAMA 1 will provide a viable containment heat removal path and the risk of those fires will be reduced such that further reductions are not expected to be cost-beneficial.	Not required on SAMA list.

Review of Columbia Generating Station Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
HV-02	Provide redundant train or means of ventilation	This SAMA is for alternate switchgear room cooling. For LSCS, switchgear room cooling is not required and this SAMA would not provide any benefit.	Not required on SAMA list.
SR-05R	Improve seismic ruggedness of MCC-7F and MCC-8F	The only seismically induced failure identified as significant for LSCS was failure of the CST (which has been addressed by other changes). Improving the seismic ruggedness of LSCS motor control centers (MCCs) would not provide any significant benefit.	Not required on SAMA list.
FL-05R	Clamp on flow instruments to certain drain lines in the control building of the radwaste building and alarm in the control room	The LSCS PRA results review included an assessment of the important flood scenarios and flood detection is available for these scenarios based on sump alarms and fire protection system actuation alarms. The addition of alarms on the building drains would not provide any significant new information or advantage in these cases. The next largest flood scenario has an RRW value of 1.003 and the response time is over 40 hours. The addition of flow instrumentation on building drains would have no measurable impact on plant risk and would not be cost-beneficial enhancement.	Not required on SAMA list.
FL-04R	Add one isolation valve in the SW, turbine SW, and fire protection lines in the control building area of the radwaste building	The LSCS PRA results review included an assessment of the important flood scenarios and remote flood isolation capability exists for these contributors, but procedures are not currently available to direct the use of these other isolation points. LSCS SAMA 9 was developed to address this issue and no additional SAMAs are required.	Functional Equivalent Already Included on the SAMA list; Industry SAMA not added.

Review of Columbia Generating Station Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
FL-06R	Additional nondestructive evaluation (NDE) and inspections (in the control building)	For LSCS, the significant flooding events are related to fire protection system breaks in the reactor building rather than in the control building. Performing inspections of the fire protection piping in the reactor building is more difficult and costly than in the proposed SAMA because for LSCS, a large portion of the inspections would have to be performed in high radiation areas. The internal events review identified procedure enhancements that could address the fire protection flooding risk that are considered to be lower cost alternatives than an enhanced inspection program (SAMAs 9). In addition, a separate SAMA was developed to install fire protection pump kill switches in the MCR that would also reduce the risk of the fire protection system breaks (SAMA 11). For LSCS, these SAMAs are more appropriate and the Columbia SAMA is not considered to require further evaluation.	Functional Equivalent Already Included on the SAMA list; Industry SAMA not added.
CC-24R	Backfeed the HPCS system with SM-8 to provide a third power source for HPCS	For LSCS, the HPCS system can be powered from the SAT or the dedicated EDG, but procedures are not available for inter-divisional cross-ties (e.g., bus 242Y to 243). Added to the LSCS SAMA list.	Added to SAMA list (SAMA 24).
CC-25R	Enhance alternate injection reliability by including RHR, SW and fire water cross-tie in the maintenance program	For LSCS, this is considered to be implemented. There are no proceduralized RHR cross-ties, but the valves that would be used to cross-tie pump suction paths are already in the maintenance rule program. For service water and fire water, there is a cross-tie between the systems and this function is included in the maintenance rule program. The fire protection system cross-tie to feedwater is also included in the maintenance rule program.	Not required on SAMA list.

Review of Columbia Generating Station Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
OT-07R	Increase operator training on systems and operator actions determined to be important from the Probabilistic Safety Assessment	Important HFEs are currently communicated to LSCS Operations and consideration is given to improving the response to those actions. Additionally, LSCS has an "Operator Response Time Program, which outlines a process to track and validate time limited actions in the design basis analyses and the PRA. These actions are validated with respect to the time required to implement them, but not necessarily given additional training and simulator practice. The quantitative benefits associated with improving training in HRA are subjective and reliability improvements are generally limited to cases where training can be provide for actions that are not currently practiced. The HFEs important to LSCS risk were reviewed to determine if there were any actions for which limited training was performed. Two HFE were identified where some risk reduction may be possible: 1) Controlling containment venting within the proceduralized pressure band, and 2) Initiating containment venting with the 2" vent/purge line to maintain pressure below the Hi DW pressure setpoint. Item 1 will be addressed by implementation of SAMA 1 and no additional SAMA is required. Some benefit could potentially be gained by including training specific to the water hammer scenario into Licensed Operator Cycle Training Plans to maintain operator proficiency in the relevant scenarios; however, recent operating experience indicates that use of the 2-inch vent purge line alone is not sufficient to prevent the high DW pressure signal and that additional steps will be required as part of the mitigation strategy. A SAMA has been added to address this training enhancement.	Added to SAMA list (SAMA 25).
FW-05R	Examine the potential for operators to control reactor feedwater (RFW) and avoid a reactor Trip	For LSCS, the transient initiating event frequencies are based on plant specific and industry data such that potential improvements to the operators' ability to control FW would not directly be reflected in the risk assessment and the benefit of such an improvement cannot be estimated reliably. No control issues have been identified for LSCS and this SAMA is not considered to be required.	Not required on SAMA list.

Review of Columbia Generating Station Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
OT-09R	For the non-Loss of Coolant Accident initiating events, credit the Z (power conversion system recovery) function	This appears to be a PRA model enhancement rather than a plant enhancement. The power conversion system is modeled and credited in the LSCS model. Not relevant.	Not required on SAMA list.
FR-11R	Install early fire detection in the following analysis units: RC-02, RC-03, RC-04, RC-05, RC-07, RC-08, RC-11, RC-13, RC-14, and RC-1A	For the LSCS fire contributors, other SAMAs have been identified that address the consequences of the fires and the risk is considered to be addressed by those SAMAs. Fire detection equipment is available in each of these areas. The reliability of early detection systems has not been established and these types of changes are not recommended as SAMAs.	Functional Equivalent Already Included on the SAMA list; Industry SAMA not added.

F.5.1.3.6 Grand Gulf

Review of Indian Point U2 Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
39	Change procedure to cross tie open cycle cooling system to enhance containment spray system.	It is not clear from the Grand Gulf SAMA analysis whether the intent of this SAMA is to cross-tie an open cycle system to RHR in order to supply the containment spray header, or to provide the RHR heat exchangers with an alternate cooling supply. For the LSCS RHR system, there are already proceduralized means of supplying the containment spray header from alternate sources (e.g., the fire protection system) and this function is already implemented. There are no existing connections between open cycle systems and the RHR SW side of the RHR heat exchanges that could be used to provide alternate cooling to the RHR system. A procedure change to allow this function is, therefore, not applicable to the LSCS design.	Not required on SAMA list.

Review of Indian Point U2 Potentially Cost-beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for LSCS	Disposition for LSCS SAMA List
42	Enhance procedures to refill condensate storage tank from demineralized water or service water system	LSCS has the capability (with procedures) to provide makeup to the CST with fire water, but the capability is not currently credited in the PRA. Additional enhancements to provide other CST makeup capabilities would provide a negligible benefit for LSCS.	Not required on SAMA list.
59	Increase operator training for alternating operation of the low pressure emergency core cooling system pumps (low-pressure coolant injection and low pressure core spray) for loss of standby service water scenarios	For LSCS, the low pressure ECCS pumps are cooled by the Core Standby Cooling System and Equipment Cooling System. Rather than cycling large pumps in scenarios where the cooling system is lost, a more effective means of maintaining injection with the ECCS pumps is considered to be through the use of portable/temporary cooling alignment, which is addressed in the LSCS importance list review by SAMA 16.	Not required on SAMA list.
Un-numbered	Revise procedures to direct the operator monitoring a running diesel generator to ensure that the ventilation system is running or take action to open doors or use portable fans	The failure of diesel generator room cooling fans and dampers are not risk significant contributors for LSCS.	Not required on SAMA list.

F.5.1.3.7 Industry SAMA Identification Summary

The important issues for LSCS are generally considered to be addressed by the SAMAs developed through the PRA importance list review. The plant changes suggested as part of that review were developed to meet the specific needs of the plant, such that those SAMAs are more likely to provide effective means of risk reduction than SAMAs taken from other sites. However, effort was made to review other industry SAMA analyses to determine if other sites identified plant changes that could be potentially cost-beneficial for LSCS based on modeling differences or other factors. For LSCS, the industry review identified two (2) unique plant enhancements that have been included in the Phase 1 SAMA list for consideration:

- Provide Inter Division 4kV AC Cross-Tie Capability (SAMA 24)

- Periodic Training on Water Hammer Scenarios Resulting from a False LOCA Signal (SAMA 25)

F.5.1.4 LSCS IPE PLANT IMPROVEMENT REVIEW

The LSCS IPE/IPEEE submittal (CECo 1994), which is based on the RMIEP analysis, did not document a definitive list of proposed plant enhancements. Instead, there are references to lists of generic IPE insights and accident management insights from the Dresden and Quad Cities IPEs. The discussion indicates that over 218 IPE and Accident Management insights were developed that were potentially applicable to LSCS, and that they were evaluated by the review team and the BWR Owners' Group; however, these insights are not specifically provided. There is no indication that any of these generic insights had the potential to significantly impact plant risk and they are not pursued further as part of the SAMA analysis.

F.5.1.5 LSCS IPEEE PLANT IMPROVEMENT REVIEW

As described in Section F.5.1.4, the IPE/IPEEE document did not provide a definitive list of potential plant improvements for LSCS; however, the IPEEE Safety Evaluation Report does state that the RMIEP fire analysis identified two potential areas for plant improvement in addition to the Accident Management insights described in section F.5.1.4. While not listed in the IPE/IPEEE, these changes are considered to be potential plant improvements related to external events and they have been reviewed as part of the SAMA analysis.

The following table summarizes the status of the potential plant enhancements resulting from the IPEEE processes and the treatment of each in the SAMA analysis.

Status of IPEEE Plant Enhancements

Description of Potential Enhancement	Status of Implementation	Disposition
Put tops on the MCR electrical panels to reduce the potential for spread of fire to the overhead cables.	Not implemented.	Current industry guidance requires cabinets to be completely and robustly sealed in order for the configuration to preclude propagation and damage to overhead cables. In its original form, the proposed enhancement to install tops on the MCR cabinets, which also have ventilation on the sides, would not have a measurable impact on fire risk and would not be cost-beneficial for LSCS. In addition, the other SAMAs have been identified to address MCR fire risk, as described in section F.5.1.6.1.2. Screened from further review.

Status of IPEEE Plant Enhancements

Description of Potential Enhancement	Status of Implementation	Disposition
Institute a program to inspect the penetration seals at the top of the switchgear panels to minimize the potential that switchgear fires might damage the overhead cables.	Not implemented.	Current industry guidance requires cabinets to be completely and robustly sealed in order for the configuration to preclude propagation and damage to overhead and nearby “targets”. The proposed inspection plan from RMEIP for these ventilated cabinets would not have a measurable impact on fire risk and would not be cost-beneficial for LSCS. In addition, the installation of the reliable hard pipe vent (SAMA 1) will mitigate about 70% of the fire risk in the switchgear rooms, as describe in section F.5.1.6.1.1. Screened from further review.

The plant changes identified in the IPEEE Safety Evaluation Report would not have a measurable impact on LSCS fire risk and are not considered further in this analysis.

F.5.1.6 EXTERNAL EVENTS IN THE LSCS SAMA ANALYSIS

The LSCS IPEEE (CECo 1994) was the result of a review of the NRC’s “Risk Methods Integration and Evaluation Program” (RMIEP) (NRC 1992b, NRC 1993). Section 7.4 of the LSCS IPEEE summarizes the external events that were considered in the analysis, which were: Aircraft Impact, Avalanche, Biological Events, Coastal Erosion, Drought, External Flooding, Extreme Winds and Tornadoes, Fog, Forest Fire, Frost, Hail, High Tide, High Lake Level or High River Stage, High Summer Temperature, Hurricane, Ice Cover, Industrial or Military Facility Accident, Internal Flooding, Landslides, Lightning, Low Lake or River Water Level, Low Winter Temperatures, Meteorite, Pipeline Accident, Intense Precipitation, Release of Chemicals in Onsite Storage, River Diversion, Sandstorm, Seiche, Seismic Activity, Snow, Soil Shrink-Swell or Consolidation, Storm Surge, Transportation Accidents, Tsunami, Toxic Gas, Turbine Generated Missiles, Volcanic Activity, and Waves.

These potential contributors were evaluated using a multi stage approach, which consisted of initial screening, bounding analysis, and detailed analysis. The RMIEP analysis indicated that the screening criteria were designed to minimize the possibility of omitting risk significant contributors while reducing the amount of detailed analysis to manageable proportions. The high level set of screening criteria that were uses are as follows:

An external event was excluded if:

- It was an event for which the plant was designed,
- The event had a significantly lower mean frequency of occurrence than other events with similar uncertainties and could result in worse consequences than those events.
- The event could not occur close enough to the plant to affect it.
- The event was included in the definition of another event.

Aside from the events for which detailed analyses had already been determine to be required (seismic, fire, and internal flooding), the following events were identified for a more detailed assessment after the initial screening process was completed:

- Military and Industrial Facilities Accidents,
- Pipeline Accidents,
- Release of Chemicals in Onsite Storage,
- Aircraft Impact,
- External Flooding,
- Transportation Accidents,
- Turbine Missiles,
- Winds and Tornadoes.

The LSCS IPEEE indicates that additional information from the LSCS Final Safety Analysis Report was used to eliminate Military and Industrial Facilities Accidents, Pipeline Accidents, and Release of Chemicals in Onsite Storage.

A probabilistic analysis was performed for the remaining five event types in addition to the fire, seismic, and internal flooding events. Apart from internal flooding, which is integrated in the current LSCS PRA model, a review of the risks associated with these event types was performed in the following subsections as part of the SAMA identification process:

- Internal Fires (Section F.5.1.6.1)
- Seismic Events (Section F.5.1.6.2)
- Winds and Tornadoes (Section F.5.1.6.3)
- Turbine Missiles (Section F.5.1.6.4)
- Transportation and Nearby Facility Accidents (Section F.5.1.6.5)
- External Floods (Section F.5.1.6.6)
- Aircraft Impact (Section F.5.1.6.7)

The external event types that were not evaluated with a probabilistic assessment in the IPEEE for LSCS are considered to be negligible contributors to risk and they are excluded from further consideration in the SAMA identification process.

The types of information available for the initiators that were evaluated by LSCS varies based on the manner in which they were addressed in the IPEEE. For instance, core damage frequency information was developed as part of the fire risk analysis that includes component level failures, while the bounding analysis for winds and tornadoes is limited to information related to the frequency of building/structure failures.

Because of the differences in the methods used to evaluate the external events risks, each of the external event contributors must be considered in a manner suiting the type of analysis performed. A summary of the review process used to identify SAMAs is provided for each of the external event types listed above, followed by a description of the method used to quantitatively incorporate external events contributions into the SAMA analysis.

F.5.1.6.1 Internal Fires

As discussed above, the techniques used to model external events vary according to the type of initiator being analyzed. For LSCS, the Fire PRA (Exelon 2009) is available for use in the SAMA analysis. However, that model is considered to be an interim implementation of NUREG/CR-6850 because not all tasks identified in that document are completely addressed or implemented in model. That is, not all tasks identified in NUREG/CR-6850 were completely addressed or implemented in the latest update due to the limited scope of the current incremental update or due to the changing state-of-the-art of industry at the time of the LSCS Fire PRA development.

NUREG/CR-6850 task limitations and other precautions regarding the Fire PRA upgrade for LSCS are as follows:

1. Multiple Spurious Operation (MSO) Review (NUREG/CR-6850 Task 2) - MSOs are reviewed and considered; however, an expert panel is not used. At the time of the LSCS Fire PRA development, the BWR Owners' Group generic list of MSOs to be considered was reviewed for applicability to LSCS. This screening process is the first step in the overall MSO review process. In future updates, the MSO process should be completed and the results incorporated as necessary.
2. Instrumentation Review (NUREG/CR-6850 Task 2) - The new requirements of NUREG/CR-6850 regarding the explicit identification and modeling of instrumentation required to support PRA credited operator actions is not addressed. The industry

treatment for this task was still in development at the time the 2009 fire analysis was performed.

3. The Balance of Plant (BOP) (NUREG/CR-6850 Task 2) - The BOP is not fully treated. BOP support system failure is conservatively assumed. Additional modeling could be conducted to reduce the fire CDF due to this assumption as resources become available in future updates.
4. Large Early Release Frequency (LERF) (NUREG/CR-6850 Task 2) - LERF is not considered. LERF is expected to be addressed in future updates.
5. Limited Analysis Iterations (NUREG/CR-6850 Task 9-12) - The process of conducting a Fire PRA is iterative, and involves identifying conservative assumptions and high risk compartments and performing analyses to refine the assumptions and reduce those compartment risks. The ability to conduct iterations is limited based on resources. The scenarios developed for the LSCS Fire PRA may benefit from further refinement as necessary for application or for future updates.
6. Multi-Compartment Review (NUREG/CR-6850 Task 11) - This subtask reviews the fire analysis compartment boundaries to ensure they are sufficiently robust to prevent the spread of fire between Fire PRA analysis compartments or that such propagations are adequately addressed by the developed scenarios. The design and plant layout of LSCS make fire propagation to multiple compartments unlikely compared to the fire risk in individual compartments. RMIEP performed a multi-compartment analysis that can be used along with the results of the Fire PRA, as necessary.
7. Seismic Fire Interactions (NUREG/CR-6850 Task 13) - This task reviews previous assessments to identify any specific interaction between suppression system and credited components or adverse impact of fire protection system interactions that should be accounted for in the Fire PRA.
8. Uncertainty and Sensitivity Analysis (NUREG/CR-6850 Task 15) - This task explores the impacts of possible variation of input parameters used in the development of the model and the inputs to the analysis on the Fire PRA results. This task is not currently addressed because the industry treatment for this task was still in development at the time the 2009 fire analysis was performed.

Some limitations of these items are:

- Item 1(MSO), represents a source of additional fire CDF contribution (i.e., if the BWROG MSO list includes MSOs not addressed in this update).
- Item 2 (Instrumentation Review) represents a potential additional fire CDF contribution that cannot be estimated at this time since the methodology was not established.
- Items 3 (BOP) and 8 (Uncertainty) are potential sources of conservatism in the results.
- Item 4 (LERF) is a future scope issue not affecting the fire CDF model.
- Items 5 (Iterations) and 6 (Multi-compartment) represent modeling assumptions that should be reviewed with each Fire PRA application to determine their applicability and/or potential impact on the decision.
- Item 7 (Seismic) is a Fire PRA application completeness issue for which the methodology was not yet established.

The approach taken for the SAMA analysis is to use the fire model results to develop potential SAMAs and to use risk insights from both the fire and internal events PRA models to approximate potential averted cost-risk for the SAMAs, as necessary. Even if it was considered appropriate to use the fire model directly for SAMA quantification, the fire model is not integrated with the most recent Level 2 and 3 analyses that are available to support the SAMA analysis. This fact prevents the evaluation of accident consequences in a manner consistent with the process used for the internal events models. Finally, the fire model is based on a previous revision of the PRA (Revision LS206C) rather than the current revision (LS213A), which introduces additional area of inconsistency.

While the fire model results are not necessarily comparable to the current PRA results, the SAMA analysis directly uses the fire CDF to develop the external events multiplier, as described in Section F.4.6.2.

The dominant fire zones, as defined in the LSCS fire PRA, were those fire zones that contributed over 5% to the fire CDF (i.e., scenarios with CDFs greater than 4.70E-07/yr based on the Unit 2 Fire CDF of 9.41E-06/yr). This threshold correlates to about 3.5% of the total CDF of 1.34E-5 (refer to Section F.4.6.2), and the largest un-reviewed fire zone represents less than 2.5% of the overall CDF (Unit 1 Zone 2F-2 at 3.36E-07/yr), or about $142,000. The dominant fire zones were the same for Units 1 and Unit 2, although the order of the MCR and Auxiliary Equipment Room is reversed. The following tables summarize the fire zone results.

Dominant LSCS Unit 1 Fire Zone (Sorted by CDF)

Fire Zone	Description	CDF	Contribution to Fire CDF[5]
4F1	UNIT 1 - DIVISION 1 ESSENTIAL SWITCHGEAR ROOM	2.67E-06	30.0%
4E3-2	UNIT 1 - DIVISION 2 ESSENTIAL SWITCHGEAR ROOM	2.67E-06	30.0%
4C1	CONTROL ROOM	5.87E-07	6.6%
4E1-2	UNIT 1 - AUXILIARY ELECTRIC EQUIPMENT ROOM - MAIN AER ROOM	3.92E-07	4.4%

[5] The Unit 1 Fire CDF is 8.91E-06/yr.

Dominant LSCS Unit 2 Fire Zone (Sorted by CDF)

Fire Zone	Description	CDF	Contribution to Fire CDF[6]
4E4-2	UNIT 2 - DIVISION 2 ESSENTIAL SWITCHGEAR ROOM	2.86E-06	30.4%
4F2	UNIT 2 - DIVISION 1 ESSENTIAL SWITCHGEAR ROOM	2.73E-06	29.0%
4E2-2	UNIT 2 – AUXILIARY ELECTRIC EQUIPMENT ROOM - MAIN AER ROOM	7.69E-07	8.2%
4C1	CONTROL ROOM	5.92E-07	6.3%

The dominant fire zones identified above were reviewed to identify potential means of reducing the risk for those zones. The results of these reviews are documented in the following subsections.

F.5.1.6.1.1 Division 1 and 2 Essential Switchgear Rooms, Units 1 and 2 (Zones 4F1, 4E3-2, 4E4-2, 4F2)

The Division 1 and 2 Essential Switchgear Rooms are the dominate contributors to the LSCS Unit 1 and Unit 2 Fire PRA risk profile. Each switchgear room contributes ~30% to the overall fire CDF for Unit 1 and Unit 2. The Essential Switchgear Rooms are:

- Unit 1 Division 1 – Fire Zone 4F1 – CDF = 2.67E-6/yr (30% of Unit 1 fire CDF)
- Unit 1 Division 2 – Fire Zone 4E3-2 – CDF = 2.67E-6/yr (30% of Unit 1 fire CDF)
- Unit 2 Division 1 – Fire Zone 4F2 – CDF = 2.73E-6/yr (29% of Unit 2 fire CDF)
- Unit 2 Division 2 – Fire Zone 4E4-2 – CDF = 2.86E-6/yr (30% of Unit 2 fire CDF)

These fire zone risk profiles are dominated by High Energy Arching Fault (HEAF) fire scenarios at the 6.9kV and 4kV switchgears that are modeled as failing the switchgear as well as target cable trays above the switchgears. These scenarios are 2.50E-6/yr (28%) of the Unit 1 fire CDF and 2.31E-6/yr (25%) of the Unit 2 fire CDF.

[6] The Unit 2 Fire CDF is 9.41E-06/yr.

Other fire scenarios in the switchgear rooms are also key contributors to the Fire PRA. These fire scenarios include severe panel fires at the 6.9kV and 4kV switchgear and 480V substation fires, as well as, 480V substation HEAF fires.

The switchgear rooms do not have an automatic fire suppression system in the fire zone. Fire detectors are present in the fire zone and fire extinguishers are available throughout. However, no credit is applied for manual suppression.

The LSCS Fire PRA indicates that the panels in the switchgear rooms are considered closed and sealed. Ventilation does exist on the back of the panels, but it is considered negligible. Unless a cabinet is not ventilated and robustly sealed (in a way that warping of doors would be limited), NUREG/CR-6850 requires that the cabinet be treated as “open”. For the LSCS Fire PRA, a factor of 0.1 was used to distinguish between severe fires that would propagate from these cabinets, and a factor of 0.9 was used to represent non-severe fires that would not propagate. This is an area that will be revisited when the fire analysis is updated.

The cutsets associated with this fire zone for Unit 2 indicate that adverse environmental conditions in the reactor building occur in about 70 percent of the cases. This is due to the fire induced failure of the containment vent. The reliable hard pipe containment vent (SAMA 1) addresses these scenarios by providing the capability to vent without support systems, and its assumed implementation will significantly reduce the contribution from this fire zone.

F.5.1.6.1.2 Main Control Room, Units 1 and 2 (Zone 4C1)

The Main Control Room (MCR) has a CDF of 5.87E-7/yr contributing 6.6% of the Unit 1 fire CDF and 5.92E-7/yr contributing 6.3% of the Unit 2 fire CDF. The MCR is shared between Unit 1 and Unit 2. The MCR is on the 768’ elevation of the Auxiliary Building and contains cables and controls related to all critical equipment modeled in the Fire PRA.

The MCR is fire zone 4C1, which does not have an automatic fire suppression system, but which does have fire detectors and fire extinguishers available throughout and is continually manned. These features are considered in the MCR abandonment calculation.

The fire scenarios postulated for the MCR are considered in three separate analyses:

1. Main Control Board (MCB) Scenarios
2. MCR Electric Panel Scenarios

3. MCR Abandonment Scenarios

Two fire scenarios from 4C1, which are among the top fire scenarios, make up 3.86E-7/yr (66%) of the Unit 1 MCR fire CDF and 3.90E-7/yr (66%) of the Unit 2 MCR fire CDF. These fire scenarios are:

- Scenario 4C1(2)-D4: MCB fire in panel 1(2)H13-P601 that results in a general transient with the failure of ADS, RCIC, RHR A, and LPCS
- Scenario 4C1(2)-J4: MCB fire in panel 1(2)PM01J resulting in a loss of 4.16 kV switchgear 1(2)AP04E, non-essential power, and the shared diesel (DG0)

The MCR analysis was based on the previous update and did not take advantage of NUREG/CR-6850, Appendix L methodology for main control board fire scenario development. This is judged to result in conservative main control board fire scenarios; however, potential means of reducing the risk associated with these scenarios have still been developed.

For Scenario 4C1-D4, fire induced failures of RCIC and ADS emphasize the importance of high pressure injection. Over 80% of the risk associated with this scenario is associated with the failure of the operators to close the turbine driven feedwater pump discharge valves after they are tripped. The action itself is intended to prevent RPV overfill and/or hotwell depletion. The flow control for these pumps is currently provided by pump speed control such that when the pumps are tripped, the flowpath remains open. When reactor pressure is reduced, which would occur as part of a gradual cooldown in this scenario, flow from the condensate pumps or heater drain system can flow in an uncontrolled manner into the RPV resulting in RPV overfill and/or hotwell depletion. A large contributor to the internal events HEP, on which the Fire HEP is based, is from the time reliability curve. For these fire scenarios where ADS is failed, the RPV pressure would remain high for a longer time than what is assumed in the HRA and the HEP may be conservative. However, the frequency of these contributors could be reduced by changing the turbine driven reactor feedwater pump (TDRFP) feedwater system logic to automatically close the TDRFP discharge valves when the pumps trip or are not running to reduce the likelihood of uncontrolled injection. This was also identified as a potential enhancement in the internal events PRA review (SAMA 10).

For scenario 4C1-J4, the fire induced loss of division I emergency power and DG0 results significantly degrades plant capabilities. In over 80% of the cases, containment venting failure leads to a containment overpressure failure, which results in failure of the ECCS systems due to adverse environmental conditions in the reactor building. Containment venting failure is driven by the failure of support systems, which will be mitigated by the reliable hard pipe containment vent (SAMA 1) because venting can be performed without support systems.

F.5.1.6.1.3 Auxiliary Electric Equipment Room - Main AEER Room, Units 1 and 2 (Zone 4E1-2, 4E2-2)

The Auxiliary Electric Equipment Room (AEER) is the second largest contributor for Unit 2 behind the essential switchgear rooms. The AEER fire zones are:

- Unit 1 Main area of the AEER – Fire Zone 4E1-2 – CDF = 3.92E-7/yr (4.4% of Unit 1 fire CDF)
- Unit 2 Main area of the AEER - Fire Zone 4E2-2 – CDF = 7.69E-7/yr (8.2% of Unit 2 fire CDF)

The largest contributing fire scenario for the Unit 1 and Unit 2 fire scenario is a bounding cable fire caused by hot work. This scenario has a fire CDF of 1.88E-7/yr (2.1%) for Unit 1 and 2.56E-7/yr (2.7%) for Unit 2. Due to the large number of cables in the AEERs no attempt was made to refine these scenarios and determine where the "pinch point" in the fire zone is (i.e. the scenarios were left as bounding scenarios in which the initiating fire leads to the failure of all equipment in the zone).

Several individual panel fires are also key contributors to the overall AEER risk profile. These panels were identified as closed and sealed in walk downs and RMIEP. Ventilation does exist on several of the panels but is considered negligible. NUREG/CR-6850 requires that fire propagation be considered even for sealed panels. However, the panels in the AEERs are small and have lower voltage than switchgears and MCCs. Therefore, the panel fire scenarios in the AEERs did not consider propagation beyond the panel.

The AEERs do not have an automatic fire suppression system in the fire zone. Fire detectors are present in the fire zone and fire extinguishers are available throughout. However, no credit is applied for manual suppression.

Because the fires do not propagate in these scenarios and because automatic fire suppression systems cannot be credited to prevent damage in the cabinet where the fire originates, automatic fire suppression is not considered to be a potential SAMA.

The largest contributing scenarios for Unit 1 are M, B, and C (total of 80% of the fire zone frequency). Scenario M is the bounding transient scenario that fails both trains of RHR and containment venting (no heat removal), ADS, RCIC, SAT TR-142, and DG0. While severe, the reliable hard pipe containment vent will provide the capability to vent without support systems, and implementation of SAMA 1 will provide a viable heat removal path for these fires. For scenarios B and C, RCIC is failed with one division of RHR ("B" for scenario "B" and "A" for scenario C). The failures that are important to these scenarios are those related to HPCS and the remaining RHR train, including some cases in which the diesel generator supporting the non-failed RHR train fails. Providing the capability to cross-tie 4kV power between divisions on the same Unit would mitigate these scenarios (SAMA 22). SAMA 1 would also mitigate many of these cases by providing a heat removal mechanism.

The largest contributing scenarios for Unit 2 are M, E, and J (total of 80% of the fire zone frequency). Scenario M is the bounding transient scenario that fails both trains of RHR and containment venting (no heat removal), RCIC, SAT TR-242, and DG2A. Scenario E is similar, but RHR B is not failed by fire. Other single failures, which are diverse in nature, lead to loss of the RHR system. While severe, the reliable hard pipe containment vent will provide the capability to vent without support systems and implementation of SAMA 1 will provide a viable heat removal path for these fires. For scenario J, the DG2A and RHR B are the primary failures and in these cases, loss of DG0 results in the loss of heat removal and vent capability. Again, the reliable hard pipe containment vent will provide the capability to vent without support systems (SAMA 1). In addition, there are cases in which DG0 fails where RHR A could be used if power was aligned to bus 241Y from bus 243. Providing the capability to cross-tie 4kV power between divisions on the same Unit would mitigate these cases (SAMA 22).

F.5.1.6.1.4 Fire SAMA Identification Summary

Based on a review of the dominant LSCS fire zone results, no unique, fire-specific SAMAs have been identified.

<u>F.5.1.6.2 Seismic Events</u>

As described in the LSCS IPEEE, a simplified seismic PRA was performed as part of the RMIEP analysis. While efforts are in progress to update the LSCS seismic risk analysis, the RMIEP analysis represents the latest available seismic analysis for the site and it has been used to support the SAMA analysis. The LSCS IPEEE indicates that the event trees used for the analysis were taken directly from the RMIEP analysis with two simplifying modifications. The first was that the systems that were dependent on offsite power were removed from the trees since a loss of offsite power was assumed for seismic events. The second was that the suppression pool cooling and containment spray systems were removed from the Large and

Medium LOCA trees and the venting system was removed from all event trees since the RMIEP analysis did not evaluate Level 2 impacts. The differences between the two models are considered to have a negligible impact on the results and because only the RMIEP analysis provides detailed descriptions of the results, the RMIEP documentation was used to support the SAMA identification process. The details of the analysis are available in NUREG/CR-4832, Volume 8.

Consistent with the goal of NEI 05-01 (NEI 2005), the seismic SAMA identification effort was focused on the dominant contributors to risk. For LSCS, about 94% of the seismic risk is associated with the following four sequences:

- LOSP-Trans-3: 42.0%
- LOSP-Trans-4: 35.3%
- LOSP-Trans-1: 11.3%
- Small-LOCA-3: 5.2%

These sequences have been reviewed as part of the SAMA identification process, the results of which are provided below on a sequence by sequence basis.

In addition, the impact of the using the LSCS 2013 seismic hazard curves on the RMIEP analysis has been investigated. The complete LSCS seismic analysis is not available for use in the SAMA analysis, but the seismic hazard curves are available and it was considered beneficial to investigate how the use of the updated hazard curves would impact the RMIEP results. The seismic CDF results were updated by applying the 2013 seismic event frequencies to the conditional core damage probabilities for each of the ranges provided in table 11.2 of the RMIEP analysis.

LOSP-Trans-3

As described in the RMIEP report, this sequence involves successful operation of the Reactor Protection System (RPS) as well as the safety relief valves (SRVs), which implies a non-ATWS event in which overpressure protection is successful and there is not a stuck open relief valve. The high pressure injection systems, HPCS and RCIC, are failed due to a seismically induced failure of the CST. ADS functions to depressurize the RPV, but LPCI and LPCS are unavailable due to random electrical support failures (offsite power and combinations of EDG, bus, relay coil, and breaker failures).

While this sequence was considered to be a dominant contributor in the RMIEP analysis, plant changes have subsequently been implemented that reduce the contribution of these events. In the RMIEP analysis, HPCS was assumed to “burn up” in these scenarios because of the lack of a low suction pressure trip for the system. In a case where the CST volume is rapidly lost due to tank failure, it was assumed that no action was possible to trip the pump to protect it before failure. Since the time of the RMIEP analysis, the normal suction path for the HPCS system was changed from the CST to the suppression pool (the CST is now only available after installation of a spool piece), so loss of the CST would not cause the immediate failure of HPCS. Failure of AC power was the dominant contributor for the low pressure injection systems, but because HPCS is supported by a separate, dedicated power division (Division III), the HPCS system would be available in most of these scenarios and the CDF associated with this sequence would be significantly reduced relative to the RMIEP analysis.

The details associated with the failure of RCIC are not clearly documented for this sequence, but it appears that RCIC is also assumed to fail due to loss of the CST. RCIC is normally aligned to the CST, has a low suction pressure trip, and auto aligns to the suppression pool on low CST level and there is no indication that RCIC would not be available in these events (i.e., even if RCIC tripped on loss of the CST, it could be aligned to the suppression pool manually if the auto alignment function failed and then restarted). Based on information in the RCIC system notebook, the “sneak circuit” failure mode is not an issue. Even though review of the system design showed the “sneak circuit” failure was unlikely, the relay associated with this failure mode was replaced in 1996 to definitively eliminate this failure mode. While it appears that RCIC would be available in this sequence, it is assumed to be failed.

The changes implemented since performance of RMIEP have reduced the contribution of this sequence and it is not considered to be a dominant contributor to risk, but AC power failures may still be a factor. Providing long term RPV makeup capability in SBO scenarios with seismically qualified equipment could provide some benefit. This could be accomplished by providing a seismically qualified low pressure injection pump with a seismically qualified diesel generator for power. In order to respond to loss of injection cases, it would be necessary to provide the capability to align the system from the MCR. A hard piped connection between the RHRSW line in the Auxiliary Building to the seismically qualified, non-safety related pump would be installed in conjunction with a discharge line that would be routed to the Unit 1 and Unit 2 Feedwater systems piping headers. The seismically qualified, non-safety related diesel generator would be permanently installed outside of the reactor building with a remote start capability that would power the injection pump. Alignment to the existing safety related battery chargers will be performed manually and will be possible within 4 hours (SAMA 26).

LOSP-Trans-4

As described in the RMIEP report, this sequence involves successful operation of the Reactor Protection System (RPS) as well as the safety relief valves (SRVs), which implies a non-ATWS event in which overpressure protection is successful and there is not a stuck open relief valve. The high pressure injection systems, HPCS and RCIC, are failed due to the failure of the reactor level instrumentation or a seismically induced failure of the CST. Automatic depressurization fails due to the RPV level instrumentation failure and manual depressurization fails due to operator error, resulting in a high pressure core melt.

The RMIEP analysis includes a discussion of the re-evaluation of the water level reference leg failure probability, which was performed after the RMIEP analysis was complete. The updated value for the reference leg failure was 3 orders of magnitude lower than the value used in the RMIEP analysis and substitution of the new value into the analysis was described as decreasing the contribution of the LOSP-Trans-4 sequence by a factor of 10. When this insight is incorporated into the sequence, it is no longer a dominant contributor and becomes similar to LOSP-Trans-3. No additional SAMAs are considered to be required to address the risk associated with this sequence.

While the SAMA identification process accounts for the re-analysis of the reference leg failure probability, the seismic CDF used in the SAMA analysis has not been reduced to reflect this change.

LOSP-Trans-1

This sequence involves successful operation of the Reactor Protection System (RPS) as well as the safety relief valves (SRVs), which implies a non-ATWS event in which overpressure protection is successful and there is not a stuck open relief valve. The HPCS system fails due to random events, but RCIC is initially successful. Failure of the heat removal system (i.e., RHR in the suppression pool cooling, shutdown cooling, and containment spray modes) results in heatup of the suppression pool and forced RPV emergency depressurization (e.g., on violation of heat capacity temperature limit). The depressurization function is successful, but random failures of the low pressure injection systems lead to loss of RPV makeup and subsequent core damage.

For cases where RCIC is the only injection system available, it would be possible to prevent core damage by changing the EOPs to allow RPV pressure to be maintained in the range of 150 to 250 psig even when containment temperature and pressure limits are violated. This would ensure the RCIC steam head is not lost in long term loss of containment heat removal scenarios. Providing a 480V AC generator to supply a battery charger would maintain plant instrumentation and control power, which would improve the reliability of this strategy (SAMA 27).

Small-LOCA-3

Neither the RMIEP report nor the IPEEE provide a detailed description of this sequence, but the event tree provides the functional successes and failures of the scenario. This sequence involves successful operation of the Reactor Protection System (RPS) as well as the safety relief valves (SRVs), which implies a non-ATWS, small LOCA event in which overpressure protection is successful and there is not a stuck open relief valve. The event tree path defines that failure of HPCS and RCIC, but the causes of the failures are not provided. ADS functions to depressurize the RPV, but LPCI and LPCS are unavailable (causes not specified) and lack of RPV makeup leads to core damage.

If the HPCS and RCIC failures are due to either the RPV water level reference leg failure or the HPCS pump “burn up” case, the contributions from this scenario maybe overestimated, as described for sequences LOSP-Trans-3 and LOSP-Trans-4. Assuming that HPCS and RCIC are failed by other causes, a potential means of mitigating these scenarios would be to install a cross-tie between the RHRSW and LPCS systems for low pressure makeup (SAMA 15). It is assumed emergency AC power is available for these LOCA cases.

Impact of 2013 LSCS Hazard Curves

At the time the SAMA analysis was performed, the LSCS seismic model was only in the early stages of development and the complete model was not available for use in the SAMA analysis; however, the development of the 2013 LSCS seismic hazard curves was complete. While it was not possible to make use of the entire LSCS seismic model, it was possible to use the latest seismic hazard curves to gain an understanding of how the RMIEP results would be impacted by the latest available seismic event frequencies.

The 2013 versions of the LSCS seismic hazard use the NRC/DOE/EPRI CEUS-SSC sources model (NRC 2012b), a revised version of the EPRI 2004-2006 ground motion attenuation model, and updated local site amplification information received from the site. The following table provides the original RMIEP frequencies along with the 2013 LSCS hazard frequencies for the same seismic intervals:

Comparison of RMIEP and 2013 LSCS Seismic Hazard

Level (or Interval)	Lower bound (g PGA)	Upper bound (g PGA)	RMIEP Freq.	2013 LSCS Freq.
1	0.18	0.27	1.10E-04	8.32E-05
2	0.27	0.36	2.90E-05	3.03E-05
3	0.36	0.46	1.10E-05	1.55E-05
4	0.46	0.58	4.70E-06	8.47E-06
5	0.58	0.73	2.10E-06	4.61E-06
6	0.73		1.00E-06	4.63E-06

These curves were used in conjunction with the conditional accident sequence probabilities provided in Table 11.2 of the RMEIP analysis to re-quantify the accident sequence frequencies. Table F.5-3a and F.5-3b provide the estimated seismic accident sequence frequencies based on the RMIEP and 2013 LSCS seismic hazard curves, respectively. A spreadsheet was used to perform the calculations and because of rounding differences, the RMIEP results provided in table F.5-3a do not exactly match those documented in Table 11.1 of the RMEIP analysis. For the purposes of this comparison, the frequencies were calculated in a similar manner for consistency.

The results indicate a slight increase in the overall seismic CDF and a small shift of some of the risk from the Level 1 interval to the mid and upper seismic intervals (Levels 3 through 6). The Level 1 and 2 intervals still represent over 60% of the risk and the use of the 2013 LSCS seismic hazard information does not appear to represent a change that would alter the conclusions of sequence reviews performed above. The updated seismic CDF of 6.6E-07/year is, however, considered to be appropriate for use in the development of the LSCS external events multiplier (Section F.4.6.2).

F.5.1.6.2.1 Seismic SAMA Identification Summary

Based on a review of the LSCS seismic results, two (2) additional seismic-specific SAMAs have been identified for inclusion in the Phase 1 SAMA list:

- Seismically Qualified Low Pressure RPV Makeup Capability (SAMA 26)
- Preclude Emergency Depressurization When RCIC is the Only Injection System Available and Provide Long Term DC Power (SAMA 27)

F.5.1.6.3 Winds and Tornadoes

The approach taken to analyze the wind and tornado event risk in the RMIEP analysis was to perform a bounding analysis. Site specific tornado and high wind event frequencies were developed in conjunction with structure response assessments for Category I and non-Category I structures. Failures of Category I structures housing critical equipment were assumed to lead to core damage, which is consistent with the bounding analysis approach. Based on the design characteristics of the non-Category I structures, failures of the non-Category I structures were not assumed to lead to core damage.

The evaluation of extreme winds and tornadoes demonstrated that extreme winds were not significant contributors to LSCS risk and therefore could be eliminated from further analysis. The median frequency of plant core damage due to tornadoes was calculated to be 3.0E-08 per year and its 95th percent confidence bound was found to be 3.0E-07 per year. No plant enhancements were suggested to mitigate tornado events based on their low contribution to the LSCS core damage frequency and no vulnerabilities were identified related to these events.

For the SAMA analysis, high wind events are not dominant contributors to plant risk and no SAMAs are required; however, SAMAs that mitigate LOOP events that could be available in high wind events represent potential means of mitigating these types of scenarios. For example, SAMA 8 may provide a means of maintaining RPV makeup in the event that a high wind event fails offsite power and the EDG building.

In conclusion, no high wind or tornado related SAMAs are required for LSCS.

F.5.1.6.4 Turbine Missiles

The approach taken to analyze the risk associated with turbine generated missiles in the RMIEP analysis was to perform a bounding analysis. As indicated in the IPEEE, the 95th percent confidence bound on the CDF due to turbine generated missiles is on the order of 1E-07 per year and the mean value is documented in the RMIEP analysis as 9.5E-08/year.

The evaluation of turbine generated missiles demonstrated that these events were not significant contributors to LSCS risk and therefore could be eliminated from further analysis. No plant enhancements were suggested to mitigate turbine generated missile events based on their low contribution to the LSCS core damage frequency and no vulnerabilities were identified related to these types of events.

For the SAMA analysis, turbine generated missile events are not dominant contributors to plant risk and no SAMAs are required.

F.5.1.6.5 Transportation Accidents

The approach taken to analyze the risk associated with transportation accidents in the RMIEP analysis was to perform a bounding analysis. The types of events considered included:

- A chemical explosion due to a transportation accident that may cause damage to Category I structures and safety related equipment,
- A toxic chemical release from a transportation accident that may drift into the control room and cause incapacitation of the operators.

The analysis considered the frequency of occurrence of transportation accidents as well as the fragility of the plant structures against accident effects. It was determined that potential chemical explosions would not damage LSCS Category I structures and that these events do not contribute to plant risk. Chemical spills were also determined not to pose a significant risk to LSCS based on the types of chemicals that would potentially be transported near the plant, the distance of the plant from the local shipping lanes and highways, and the availability of specific chemical detectors in the main control room ventilation system. No plant enhancements were suggested to mitigate events related to transportation accidents based on their low contribution to the LSCS core damage frequency and no vulnerabilities were identified related to these types of events.

For the SAMA analysis, transportation accidents are not significant contributors to plant risk and no SAMAs are required. For the purposes of evaluating the external events multiplier, the same

CDF estimated for the risk associated with high winds (3.0E-08/year) is used to represent the risk from transportation accidents, which is considered to be conservative.

F.5.1.6.6 External Floods

The approach taken to analyze the risk associated with external flood events in the RMIEP analysis was to perform a bounding analysis. The analysis considered the following events:

- Probable maximum flood of the Illinois River,
- Probable maximum precipitation with antecedent standard project storm on the cooling lake and its drainage area,
- Probable maximum precipitation event at the plant site.

The LSCS plant grade is 710' mean sea level (MSL) and structure floor elevations are slightly higher at 710.5' MSL. The maximum probable flood event for the Illinois River, which is normally at levels below 500' MSL, was determined to be only 522' MSL when coincident wave effects were considered. Flooding of the Illinois River was determined not to affect plant safety.

Analysis of the probable maximum precipitation event on the cooling lake identified that overflow from the lake would flow away from the plant and into the creeks and gullies that empty into the Illinois River. In cases where the peripheral dikes of the cooling lake are breached, the impounded water would similarly drain to the same creeks and gullies and not impact the plant.

Local intense precipitation events at the site were also analyzed and it was determined that the resulting level of the flood water would be less than the 710.5' MSL elevation of the LSCS structure floors. The analysis included conservative assumptions related to the duration of the probable maximum precipitation event, the availability of drainage paths, and the permeation of water into the ground. It was also identified that the structure doors are leak-tight such that flood water elevations above 710.5' MSL would not necessarily result in the flooding of plant buildings. No plant enhancements were suggested to mitigate external flood events based on their low contribution to the LSCS core damage frequency and no vulnerabilities were identified related to these types of events.

For the SAMA analysis, external flooding events are not significant contributors to plant risk and no SAMAs are required. For the purposes of evaluating the external events multiplier, the same CDF estimated for the risk associated with high winds (3.0E-08/year) is used to represent the risk from external flooding events, which is considered to be conservative.

F.5.1.6.7 Aircraft Impact

The approach taken to analyze the risk associated with accidental aircraft impact in the RMIEP analysis was to perform a bounding analysis. As indicated in the IPEEE, the median CDF for these events was estimated to be 5.0E-07/year and the RMIEP analysis indicates that the 95th percent confidence bound on the CDF due to accidental aircraft impact is 1E-06/year. In this analysis, core damage was assumed to occur for any aircraft impact on a Category I structure that results in back face scabbing of the building wall, which is considered to be conservative.

The largest accidental aircraft risks were associated with twin engine plane crashes on the Reactor Building and Auxiliary Building. This is primarily because single engine planes were determined not to be capable of causing back scabbing on the walls of these buildings and the crash rate of commercial aircraft is relatively low compared to that of twin engine planes. The Unit 2 Diesel Generator Building was screened from the analysis due to its small size, because it is protected on two sides by other nearby buildings, and because the swing diesel generator would be available to provide power from the Unit 1 Diesel Generator Building if an aircraft impacted the Unit 2 Diesel Generator Building. These are relatively high level insights and do not provide any specific information about the potentially important equipment failures in these scenarios.

No plant enhancements were suggested in the IPEEE or RMIEP to mitigate accidental aircraft impact events based on their low contribution to the LSCS core damage frequency and no vulnerabilities were identified related to these types of events. It is recognized that the types of credible threats to nuclear facilities by aircraft have changed since the time the RMIEP analysis was performed. However, substantial efforts have been made within the industry to address this issue in conjunction (e.g., the development of extreme damage mitigation guidelines) with other forms of sabotage. Given that this topic is addressed by other industry initiatives, intentional aircraft impact events are considered to be out of the scope of the SAMA analysis, which is a mitigation alternatives analysis performed for purposes of compliance with NEPA and 10 C.F.R. Part 51. No additional SAMAs are considered to be required to address aircraft impact events.

F.5.2 PHASE 1 SCREENING PROCESS

The initial list of SAMA candidates is presented in Table F.5-4. The process used to develop the initial list is described in Section F.5.1.

The purpose of the Phase 1 analysis is to use high-level knowledge of the plant and SAMAs to preclude the need to perform detailed cost-benefit analyses on them. The following screening criteria were used:

- Applicability to the Plant: If a proposed SAMA does not apply to the LSCS design, it is not retained. Similarly, any SAMAs that have already been implemented by EGC or any modifications implemented by EGC that achieve the same results as a SAMA can be screened as they are not applicable to the current plant design. These criteria are not often explicitly used in the Phase I analysis because the SAMA identification methodology generally excludes such SAMAs; however, they are listed as a possible screening method given that there may be circumstances in which a SAMA would be included in the list even if it is not relevant to the site. An example may be the inclusion of a high profile SAMA that is well known in the industry, but not applicable to the specific site design. Such a SAMA may be included for documentation purposes. Another example may be an unimplemented SAMA from the IPE that has been superseded by another plant enhancement.
- Implementation Cost Greater than Screening Cost: If the estimated cost of implementation is greater than the MACR (refer to Section F.4.6), the SAMA cannot be cost-beneficial and is screened from further analysis.

Table F.5-4 provides a description of how each SAMA was dispositioned in Phase 1 (2 SAMAs were screened on excessive implementation cost). Those SAMAs that required a more detailed cost-benefit analysis are passed to the Phase 2 analysis and evaluated in Section F.6. Table F.6-1 contains the Phase 2 SAMAs.

F.6 PHASE 2 SAMA ANALYSIS

The SAMA candidates identified as part of the Phase 2 analysis are listed in Table F.6-1. The base PRA model was manipulated to simulate implementation of each of the proposed SAMAs and then quantified to determine the risk benefit. Truncation values and binning cutoffs are the same as used in the base PRA model, including Level 2 endstates.

In general, in order to maximize the potential risk benefit due to implementation of each of the SAMAs, the failure probabilities assigned to new basic events, such as human error probabilities (HEPs), were optimistically chosen so as not to inadvertently screen out any potential cost-beneficial SAMAs. Also, any new model logic that was added to the PRA model in order to simulate SAMA implementation was also simplified and optimistically configured to achieve the same effect.

Determining whether or not any given Phase 2 SAMA is potentially cost-beneficial involved calculating what is known as the averted cost-risk, which was obtained by a multi-step process that includes the use of the baseline MACR as well as the internal events PRA results and a multiplier to account for external events contributions.

- The averted cost-risk is the difference between the baseline MACR and the MACR for the configuration in which the SAMA has been implemented ($MACR_{SAMA}$). The $MACR_{SAMA}$ includes the internal events contribution and the external events contribution.
- The internal events portion of the $MACR_{SAMA}$ is calculated in the same manner as for the baseline MACR using the CDF, Level 2 PRA results, etc., as shown in Sections F.4.1 through F.4.6.1.
- The contribution from the external events to the $MACR_{SAMA}$ is accounted for by multiplying the internal events $MACR_{SAMA}$ by the External Events Multiplier (refer to section F.4.6.2).

For some SAMAs identified by the fire and seismic results review, the internal events PRA does not provide a means of modeling the impact of the SAMA. In these cases, the averted cost-risk is estimated using insights from the external events model/documentation and information from the internal events MACR calculation. The averted cost-risk is obtained by multiplying the internal events contribution to the MACR by the ratio of the CDF eliminated by the SAMA to the base internal events CDF.

- The assumption is that the fire and seismic CDFs are proportional to the internal events MACR. For example, if the SAMA is assumed to eliminate the entire CDF associated with Unit 2 fire zone 4E2-2, the averted cost risk would be (7.69E-07 / 2.58E-06 * $1,088,000 = $324,291)

Finally, a SAMA is determined to be potentially cost-beneficial if its net value is positive. The net value is determined by the following equation:

Net Value = averted cost-risk – cost of implementation

The implementation costs used in the Phase 1 and 2 analyses consist of industry estimates, LSCS specific estimates, or in some cases, combinations of these two sources. It should be noted that LSCS specific implementation costs do include contingency costs for unforeseen difficulties, but do not account for any replacement power costs that may be incurred due to consequential shutdown time unless specifically noted. The implementation costs were developed on a site basis to account for cost sharing between units, and then divided by a factor of 2 to obtain a single unit implementation cost (which is consistent with the single unit averted cost-risk calculation that is performed). Table F.5-4 provides implementation costs for each Phase 1 and Phase 2 SAMA.

The following sections describe the cost-benefit analysis that was used for each of the Phase 2 SAMA candidates.

It should be noted that apart from fire considerations, LSCS units 1 and 2 are essentially identical in design and operation. The differences associated with fire-related issues have been addressed by performing unit specific fire SAMA identification tasks and by using unit-specific risk insights for quantification, when relevant. SAMAs developed to prevent or mitigate fire damage or propagation in a specific fire scenario required a unit specific quantification using the method described above. Unit-specific fire SAMAs are applicable only to the unit for which they were derived. SAMAs identified to mitigate the impact of fire damage (e.g., SAMA 10 – CHANGE THE LOGIC TO CLOSE THE TURBINE DRIVEN FEEDWATER PUMP DISCHARGE VALVES WHEN THE PUMPS ARE NOT RUNNING) were all also applicable to the internal events model and the External Events Multiplier was used to account for any fire related benefits for those types of SAMAs.

For all non-fire based SAMAs, the Unit 2 PRA model was employed to evaluate the risk benefits and averted costs for each of the SAMAs, and was viewed as also being applicable to Unit 1. That is, if a particular SAMA proves potentially cost-beneficial for Unit 2, it will likewise be potentially cost-beneficial for Unit 1 given the essentially identical designs of Units 1 and 2.

F.6.1 SAMA 1: INSTALL RELIABLE HARD PIPE CONTAINMENT VENT

This is already a commitment for LSCS, but it has not yet been installed and is not modeled in the PRA. This SAMA will prevent vent path failure within the reactor building and will provide a means of safely operating the containment vent when normal support systems are unavailable (non-adverse environment for use of portable pneumatic supply or manual valve operation). This SAMA is used to track this enhancement and to facilitate the interpretation of the results (for example, by providing a description of the changes used to model SAMA 1 and to show how implementation impacts the results).

<u>Assumptions:</u>

This SAMA eliminates all support system dependencies.

The hard pipe vent eliminates vent path ruptures and leaks.

This SAMA reduces the complexity of venting and the failure probability of the operator action is reduced to 1.0E-04.

The action to control containment pressure during the venting process is still required to maintain adequate NPSH for the ECCS pump. No changes to this operator action's reliability are assumed due to implementation of this SAMA.

SAMA 1 is not designed to accommodate ATWS loads and no additional credit is taken for venting in ATWS scenarios.

The common cause failure probability of the valves in reliable hard pipe containment vent is negligible.

For the cases in which containment venting is part of a joint human error probability (JHEP), it will typically not be the chronologically first human failure event (HFE) in the action chain and the probability of the failure will be dominated by the dependence level rather than the independent failure probability of the HFE. As a result, no changes are made to the JHEPs that include the containment venting action.

The reliable hard pipe containment vent valves are designed to open against high differential pressures.

<u>PRA Model Changes to Model SAMA:</u>

The model was modified to incorporate this SAMA by eliminating the support system dependencies, improving the reliability of the venting action to reflect simplification of the controls, and eliminating the events related to vent path rupture and leakage.

<u>Model Change(s):</u>

The following modeling changes were made:

- Gate CV1: Deleted gate CV-122, deleted event 2CVPHRXENVIRMF--.
- Gate DWV: Deleted gate SA-TOTAL-LOSS
- Gate PCV: Deleted gate SA-TOTAL-LOSS
- Gate DWVX: Deleted gate DW-PATH-FAILS.
- Gate PCVX: Deleted gate CONT-PATH-FAILS, deleted event 2CVAV31343640DCC.
- Gate FC-VENTDW: Deleted gate FC-VNTEQFAIL.
- Gate CV-OPS-CONT: deleted event 2CVPH-CYCLES-F--.
- Events for adverse environment impacts from venting set to 0.0:
    - 2AD--VENT----F--(ADS FAILS DUE TO STEAM RELEASE)

  - 2CR--VENT----F-- (COND PROB OF CRD FAILURE GIVEN STEAM RELEASE)
  - 2HC--VENT----F-- (COND PROB OF HPCS FAILURE GIVEN STEAM RELEASE)
  - 2SY--VENT----FCC (CCF OF HPCS & CRD & LPCI & LPCS GIVEN VENT TO RB)
  - 2SY--VENT1---FCC (CCF OF HPCS & CRD & LPCI & LPCS GIVEN VENT TO STEAM TUNNEL)
  - BFPOP-DFPENV-H-- (HEP: OP FAILS TO ALIGN DFP DUE TO ADVERSE ENV IN TB (VENT TO RB OR CNTNMT FAIL))
  - BFPOP-DFPENV1H-- (HEP: OP FAILS TO ALIGN DFP DUE TO ADVERSE ENV IN TB (VENT TO STEAM TUNNEL))
- Gate HTR-DRN-OP-QUV: Deleted gate CTFAIL-HD.
- Gate DFP-MU-VT: Deleted gate DFP-ENVIRON.
- 2CVOPVENT----H-- (HEP: OPERATOR FAILS TO INITIATE PRIMARY CONTAINMENT VENTING): Basic event probability changed in the recovery file to 1.0E-04.
- 2HDOP-HTR-DRNH-- (HEP: OPERATOR FAILS TO ALIGN HEATER DRAIN DURING DBA LOCA): Basic event probability changed from 0.21 to 9.7E-02 to reflect the impact of being able to perform the action in nominal conditions rather than adverse conditions (reduced stress for execution).

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	1.87E-06	4.53	$30,472
Percent Change	27.5%	36.3%	42.9%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.30E-08	1.34E+00	1.34E+00	$7,222	$7,204
H/E	5.93E-08	5.82E-08	3.14E-01	3.08E-01	$2,763	$2,712
H/I	1.90E-08	3.74E-09	1.08E-01	2.12E-02	$954	$188
M/E	2.14E-07	1.99E-07	1.58E+00	1.47E+00	$9,395	$8,736
M/I	9.27E-07	3.23E-07	3.58E+00	1.25E+00	$32,723	$11,402
L/E	3.88E-07	3.87E-07	8.57E-02	8.55E-02	$124	$123
L/I	1.45E-07	8.70E-08	1.03E-01	6.17E-02	$177	$106
INTACT	7.45E-07	7.29E-07	1.62E-03	1.58E-03	$1	$1
Total	2.58E-06	1.87E-06	7.11E+00	4.53E+00	$53,358	$30,472

Applying the process described in Section F.4 yields an internal events cost-risk of $645,889. After accounting for "round up" of the base internal events cost-risk, this value is $646,706. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{\text{SAMA}} = \$646{,}706 * 5.2 = \$3{,}362{,}871$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 1 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
LSCS Unit 2	$5,657,600	$3,362,871	$2,294,729

Because implementation of this SAMA is planned for LSCS, a net value is not required for this SAMA. If the implementation cost of $12,940,000 is used, however, the net value would be -$10,645,271 ($2,294,729 - $12,940,000), implying that SAMA 1 is not cost-beneficial.

F.6.2 SAMA 2: AUTOMATE SUPPRESSION POOL COOLING

Suppression pool cooling initiation is a reliable action, but for non-LOCA events, automating SPC initiation on high suppression pool temperature could further improve the reliability of the containment heat removal function.

Many of the largest contributors to LSCS risk include the failure to align SPC for containment heat removal, either alone, or in combination with other mitigating actions, such as primary containment venting. These scenarios lead to failure of primary containment and a release of steam to the reactor building. The harsh reactor building environment resulting from the steam release often results in the failure of the injection systems located in the reactor building and prevents further operator actions in the building. Automating SPC initiation will reduce the frequency of these contributors.

<u>Assumptions:</u>

One of the conditions of this SAMA's design is that SPC auto start will not be allowed for LOCA events in order to prevent the alignment of an RHR train to SPC when the RHR trains may all be needed for RPV makeup. However, the contributions from the failure to align SPC in LOCA events is small relative to non-LOCA events and for simplicity, this SAMA is assumed to apply to all initiating events in which manual alignment of SPC is currently required.

If the automatic SPC initiation signal fails, no credit is taken for manual initiation.

<u>PRA Model Changes to Model SAMA:</u>

The fault tree was modified to incorporate the automation of SPC alignment by changing the independent basic event IDs for SPC initiation to alternate IDs. This accomplishes two functions:

- It allows the assignment of alternate failure probabilities that are representative of an automated function, and
- It will prevent the recovery logic from identifying SPC initiation failures as human actions and preclude the SPC initiation failures from dependent human error combinations.

<u>Model Change(s):</u>

The following modeling changes were made:

- 2RHOPSPCINIT-H-- (HEP: OPERATOR FAILS TO INITIATE SUPPRESSION POOL COOLING (NON-ATWS)): Basic event ID changed to SAMA2. Failure probability changed from 0.1 to 1.0E-6.
- 2RHOPSPCLATE-H-- (HEP: OPERATOR FAILS TO INITIATE SPC LATE GIVEN EARLY FAILURE (COND PROB)): Basic event ID changed to SAMA2-LATE. Failure probability changed from 0.1 to 1.0 (the late conditional failure is always combined with the early failure event and has been set to 1.0 to preserve a total initiation failure probability of 1.0E-06).
- 2RHOPSPC-ATWSH-- (HEP: OPERATOR FAILS TO INITIATE SUPPRESSION POOL COOLING (ATWS)): Basic event ID changed to SAMA2-ATWS. Failure probability changed from 0.1 to 1.0E-6

<u>Results of SAMA Quantification:</u>

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.22E-06	5.71	$40,120
Percent Change	14.0%	19.7%	24.8%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,222
H/E	5.93E-08	6.24E-08	3.14E-01	3.30E-01	$2,763	$2,908
H/I	1.90E-08	1.73E-08	1.08E-01	9.79E-02	$954	$868
M/E	2.14E-07	1.98E-07	1.58E+00	1.46E+00	$9,395	$8,692
M/I	9.27E-07	5.65E-07	3.58E+00	2.18E+00	$32,723	$19,945
L/E	3.88E-07	5.32E-07	8.57E-02	1.18E-01	$124	$170
L/I	1.45E-07	2.58E-07	1.03E-01	1.83E-01	$177	$315
INTACT	7.45E-07	5.04E-07	1.62E-03	1.09E-03	$1	$0
Total	2.58E-06	2.22E-06	7.11E+00	5.71E+00	$53,358	$40,120

Applying the process described in Section F.4 yields an internal events cost-risk of $836,093. After accounting for “round up” of the base internal events cost-risk, this value is $836,910. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$836{,}910 * 5.2 = \$4{,}351{,}932$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 2 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
LSCS Unit 2	$5,657,600	$4,351,932	$1,305,668

Based on a $400,000 cost of implementation for LSCS, the net value for this SAMA is $905,668 ($1,305,668 - $400,000), which indicates this SAMA is potentially cost-beneficial.

F.6.3 SAMA 3: PASSIVE VENT PATH

For loss of containment heat removal scenarios, the reliability of the containment venting function could be improved by installing a passive vent path. If the suppression chamber vent path were equipped with a rupture disk in parallel with the remotely operated vent path, a scrubbed release path would be available to prevent containment failure in the event that normal venting fails. The rupture disk failure pressure would have to be less than the ultimate containment strength to ensure it would rupture before the containment, but consideration could also be given to a lower pressure to ensure SRVs could remain operable to support low pressure injection in loss of containment heat removal cases. Effectiveness is contingent on the implementation of the hard pipe vent.

Assumptions:

SAMA 1 has been implemented (the model used to evaluation SAMA 1 is used as the starting point for the additional changes described here to model the passive vent).

A rupture disk helps ensure that a containment failure does not occur in undesirable areas of the drywell and wetwell, but because the rupture disk is designed to fail at a lower pressure than other parts of the containment, radioactive releases would be expected to occur earlier than they would with the current plant configuration. While release from the passive vent path is considered to be “scrubbed”, which would result in a lower dose relative to an unscrubbed release, the earlier release time may result in the more of the population being impacted by the plume (before evacuation is complete).

The passive vent reliability (appropriate rupture disk failure) can be approximated by the failures of the valves in the existing vent path (with the support system dependencies removed).

PRA Model Changes to Model SAMA:

In order to approximate the impact of a passive vent, the basic event for the operator action for venting was replaced with a new placeholder event with a value of 1.0E-06 (prevents the creation of dependent operator actions including the vent action). The hardware failures associated with the vent path valves have been retained to approximate the potential failures of the rupture disk (with the support system dependencies removed).

Model Change(s):

The model changes described for SAMA 1 are also applicable here.

In addition, the following changes were made to the model:

- 2CVVT-VENT---M-- (VQ CONTAINMENT VENT / PURGE SYSTEM MUA): Event deleted.

- 2CVOPVENT----H-- (HEP: OPERATOR FAILS TO INITIATE PRIMARY CONTAINMENT VENTING): Basic event changed to “SAMA3” and assigned a failure probability of 1.0E-06.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	1.65E-06	3.47	$21,036
Percent Change	36.0%	51.2%	60.6%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.30E-08	1.34E+00	1.34E+00	$7,222	$7,204
H/E	5.93E-08	5.82E-08	3.14E-01	3.08E-01	$2,763	$2,712
H/I	1.90E-08	2.54E-09	1.08E-01	1.44E-02	$954	$128
M/E	2.14E-07	1.87E-07	1.58E+00	1.38E+00	$9,395	$8,209
M/I	9.27E-07	7.23E-08	3.58E+00	2.79E-01	$32,723	$2,552
L/E	3.88E-07	3.87E-07	8.57E-02	8.55E-02	$124	$123
L/I	1.45E-07	8.70E-08	1.03E-01	6.17E-02	$177	$106
INTACT	7.45E-07	7.73E-07	1.62E-03	1.68E-03	$1	$1
Total	2.58E-06	1.65E-06	7.11E+00	3.47E+00	$53,358	$21,036

Applying the process described in Section F.4 yields an internal events cost-risk of $466,051. After accounting for “round up” of the base internal events cost-risk, this value is $466,868. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$466,868 * 5.2 = \$2,427,714$$

SAMA 3 assumes implementation of SAMA 1 in order to provide a viable vent path for the passive vent. Because LSCS is committed to install the reliable hard pipe containment vent (for reasons unrelated to the SAMA analysis), the averted cost-risk of SAMA 3 is considered to be the difference between the SAMA 1 “revised cost-risk” value reported in Section F.6.1 ($3,362,871) and the cost-risk for the configuration of the plant with both SAMAs 1 and 3 implemented ($2,427,714). Therefore, the averted cost-risk for this SAMA is $935,157 ($3,362,871 - $2,427,714).

Based on a $1,000,000 cost of implementation for LSCS, the net value for this SAMA is -$64,843 ($935,157 - $1,000,000), which indicates this SAMA is not cost-beneficial.

F.6.4 SAMA 4: INSTALL A KEYLOCK MSIV LOW LEVEL ISOLATION BYPASS SWITCH

Operator errors are some of the largest contributors to ATWS scenarios, which are complicated by the short times available for response. One of the more time limited actions in these scenarios is the action to bypass the main steam isolation valve (MSIV) low level isolation signal, which is currently an action that requires the installation of jumpers. Providing a switch in the MCR that would bypass the isolation logic would simplify the bypass action and provide more time margin for the power/level control actions for these scenarios. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators are directed to immediately lower level to a control band above the MSIV closure setpoint and given the option to bypass the MSIV low level isolation logic before lowering level further.

<u>Assumptions:</u>

It is assumed that this SAMA reduces the failure probability of the independent operator action to bypass the MSIV low level isolation logic to 1.0E-05.

The action to bypass the MSIV low level isolation logic occurs early in the accident scenario. Because the timing for this action could arguably be the chronologically first action in most operator action combinations; a reduced HEP for this action would significantly reduce most of the associated JHEPs. For simplicity, the JHEPs that include this action are assumed to be eliminated.

<u>PRA Model Changes to Model SAMA:</u>

The independent HEP to bypass the MSIV low level isolation interlock was set to 1.0E-5 and the JHEPs that include this action have been eliminated.

Model Change(s):

The following modeling changes were made:

- 2MSOPMSIVINLKH-- (HEP: OPERATOR FAILS TO BYPASS LOW LEVEL MSIV INTERLOCK): Basic event ID changed to "SAMA4". Failure probability changed from 0.7 to 1.0E-5.
- 2MSOPMSIVINLKHSU (HEP: OP SUCCESSFULLY BYPASSES MSIV LOW LEVEL INTERLOCK): Probability changed from 0.3 to 9.9999E-01 in the fault tree.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.16E-06	6.23	$47,928
Percent Change	16.3%	12.4%	10.2%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,222
H/E	5.93E-08	4.82E-08	3.14E-01	2.55E-01	$2,763	$2,246
H/I	1.90E-08	1.90E-08	1.08E-01	1.08E-01	$954	$954
M/E	2.14E-07	1.18E-07	1.58E+00	8.72E-01	$9,395	$5,180
M/I	9.27E-07	9.09E-07	3.58E+00	3.51E+00	$32,723	$32,088
L/E	3.88E-07	2.14E-07	8.57E-02	4.73E-02	$124	$68
L/I	1.45E-07	1.39E-07	1.03E-01	9.86E-02	$177	$170
INTACT	7.45E-07	6.30E-07	1.62E-03	1.37E-03	$1	$1
Total	2.58E-06	2.16E-06	7.11E+00	6.23E+00	$53,358	$47,928

Applying the process described in Section F.4 yields an internal events cost-risk of $967,518. After accounting for "round up" of the base internal events cost-risk, this value is $968,335. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$968,335 * 5.2 = \$5,035,342$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 4 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
LSCS Unit 2	$5,657,600	$5,035,342	$622,258

Based on a $635,242 cost of implementation for LSCS, the net value for this SAMA is -$12,984 ($622,258 - $635,242), which indicates this SAMA is not cost-beneficial.

F.6.5 SAMA 5: AUTOMATE STANDBY LIQUID CONTROL (SBLC) INITIATION

ATWS events rely on timely initiation of the SBLC system for mitigation. A potential means of improving the reliability of this function would be to automate system initiation, as is that case at Limerick Generation Station.

Assumptions:

It is assumed that this SAMA reduces the failure probability of the SBLC initiation to a negligible value.

No credit is taken for manual SBLC initiation in the event that automatic actuation fails.

It is assumed that if the SBLC system is available, than all support systems required for automatic initiation would also be available.

PRA Model Changes to Model SAMA:

The automatic SBLC initiation capability is modeled by manipulation of the basic events associated with SBLC initiation. The early SBLC initiation basic event ID (2SLOP-LVLCTRLH--) was changed to “SAMA5” and set to a probability of 1.0E-06. This reduces the independent failure contribution to a small value and prevents the inclusion of dependent operator action combinations with SBLC initiation failures, which is consistent with the automation of the action.

Model Change(s):

The following modeling changes were made:

- 2SLOP-IN-ERLYH-- (HEP: OPERATOR FAILS TO INITIATE SBLC EARLY): Basic event ID changed to “SAMA5”. Failure probability changed from 0.1 to 1.0E-6.

- 2SLOP-IN-LATEH-- (HEP: OPERATOR FAILS TO INITIATE SBLC LATE (COND PROB)): Basic event ID changed to “SAMA5-L”. Failure probability changed from 0.1 to 0.0 (a conditional late failure is not applicable to an automated action).

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.38E-06	6.59	$50,215
Percent Change	7.8%	7.3%	5.9%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,222
H/E	5.93E-08	5.31E-08	3.14E-01	2.81E-01	$2,763	$2,474
H/I	1.90E-08	1.90E-08	1.08E-01	1.08E-01	$954	$954
M/E	2.14E-07	1.53E-07	1.58E+00	1.13E+00	$9,395	$6,717
M/I	9.27E-07	9.23E-07	3.58E+00	3.56E+00	$32,723	$32,582
L/E	3.88E-07	2.80E-07	8.57E-02	6.19E-02	$124	$89
L/I	1.45E-07	1.45E-07	1.03E-01	1.03E-01	$177	$177
INTACT	7.45E-07	7.20E-07	1.62E-03	1.56E-03	$1	$1
Total	2.58E-06	2.38E-06	7.11E+00	6.59E+00	$53,358	$50,215

Applying the process described in Section F.4 yields an internal events cost-risk of $1,018,781. After accounting for “round up” of the base internal events cost-risk, this value is $1,019,598. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$1,019,598 * 5.2 = \$5,301,910$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 5 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
LSCS Unit 2	$5,657,600	$5,301,910	$355,690

Based on a $400,000 cost of implementation for LSCS, the net value for this SAMA is -$44,310 ($355,690 - $400,000), which indicates this SAMA is not cost-beneficial.

F.6.6 SAMA 6: CREATE ECCS SUCTION STRAINER BACKFLUSH CAPABILITY WITH RHRSW

For some LOCA contributors, common cause plugging of the ECCS suction strainers fails makeup/heat removal. Connecting the RHRSW system to the RHR pump suction line upstream of the F004A/B valves could provide a means of backflushing the system in conjunction with steps to close the F004A/B valves during the backflush.

The backflush capability is used in LOCA scenarios, which require a rapid response for success. The backflush capability for this SAMA can be aligned from the main control room by opening the cross connect MOVs and closing the F004A/B valve(s) to ensure water is forced through the ECCS strainers.

Assumptions:

The backflush operation can be performed in time to mitigate even large LOCA events.

The backflush function is 100% reliable.

The backflush connection cannot be used as an injection source to the RPV due to losses through the RHR pumps.

PRA Model Changes to Model SAMA:

The contribution related to CCF strainer clogging was eliminated by setting the corresponding basic events in the cutset files to 0.0.

Model Change(s):

The following change was made to the cutset files:

- 2CNFLIORV----PCC (CCF (PLUGGING) OF ECCS SUCT STRAINERS (IORV / SORV)): Probability changed to 0.0.
- 2CNFLNMLLOCA-PCC (CCF (PLUGGING) OF ECCS SUCT STRAINERS (NON-LOCA / IORV / SORV)): Probability changed to 0.0.
- 2CNFLMLLOCA—PCC (CCF (PLUGGING) OF ECCS SUCT STRAINERS (LOCA)): Probability changed to 0.0.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.55E-06	7.01	$52,598
Percent Change	1.2%	1.4%	1.4%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,222
H/E	5.93E-08	5.92E-08	3.14E-01	3.13E-01	$2,763	$2,759
H/I	1.90E-08	1.89E-08	1.08E-01	1.07E-01	$954	$949
M/E	2.14E-07	2.10E-07	1.58E+00	1.55E+00	$9,395	$9,219
M/I	9.27E-07	9.11E-07	3.58E+00	3.52E+00	$32,723	$32,158
L/E	3.88E-07	3.79E-07	8.57E-02	8.38E-02	$124	$121
L/I	1.45E-07	1.39E-07	1.03E-01	9.86E-02	$177	$170
INTACT	7.45E-07	7.50E-07	1.62E-03	1.63E-03	$1	$1
Total	2.58E-06	2.55E-06	7.11E+00	7.01E+00	$53,358	$52,598

Applying the process described in Section F.4 yields an internal events cost-risk of $1,071,921. After accounting for "round up" of the base internal events cost-risk, this value is $1,072,738. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$1,072,738 * 5.2 = \$5,578,238$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 6 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
LSCS Unit 2	$5,657,600	$5,578,238	$79,362

Based on a $2,900,000 cost of implementation for LSCS, the net value for this SAMA is -$2,820,638 ($79,362 - $2,900,000), which indicates this SAMA is not cost-beneficial.

F.6.7 SAMA 7: WATER HAMMER PREVENTION

For LSCS, a high drywell pressure signal (2 psig in the drywell) will result in the generation of a LOCA signal independent of RPV water level. In certain scenarios initiated by non-LOCA events, this can lead to conditions that will result in a water hammer event.

In non-LOCA transient scenarios, the heat load rejected to the containment is sufficient to prompt the initiation of suppression pool cooling (SPC), but even with SPC in operation, the drywell pressure will reach 2 psig and a LOCA signal will register. If a consequential loss of offsite power occurs with the LOCA signal, the RHR discharge line can drain to the suppression pool in the ~45 seconds between RHR pump load shed and the time it is reloaded on the diesel backed bus, which sets up a water hammer condition in the voided pipe.

A potential means of preventing this evolution would be to alter the LOCA signal logic to require both high drywell pressure AND low RPV water level for initiation (as is the case for Limerick Generating Station). This will prevent the generation of a LOCA signal in transient scenarios where an operating train of RHR in SPC mode would be vulnerable to a water hammer event. This could also have the added benefit of simplifying the operators' response to loss of offsite power events where the LOOP signal has caused the EDGs to start and load and an ECCS signal is subsequently received due to loss of containment cooling (high drywell pressure). In this LOOP-delayed LOCA scenario, the operators are required to take many actions to handle the automatic actuations that occur due to the LOCA signal. This scenario is not specifically modeled in the PRA.

Assumptions:

This SAMA will completely eliminate the water hammer events related to the scenarios in which SPC is placed into service after the initiating event and a consequential loss of offsite power occurs after the LOCA signal.

This SAMA does not address the water hammer scenarios in which SPC is in operation prior to a LOOP initiating event and a high drywell pressure/LOCA signal subsequently occurs because the model already assumes that the system start signal from the LOCA signal is blocked. Water hammer in these scenarios is caused by the failure to properly fill and vent the RHR system before SPC start is required to prevent reaching the heat capacity temperature limit.

No adverse impact on plant risk results from requiring both high drywell pressure and low RPV water level to generate a LOCA signal.

PRA Model Changes to Model SAMA:

The water hammer events were eliminated from the results through manipulation of the cutsets. The relevant water hammer scenarios are all characterized by two events that identify the RHR train that is placed in SPC mode in response to the high suppression pool temperature. Setting these events to 0.0 approximates the impact of eliminating the water hammer events associated with the LOCA signal actuated solely on high drywell pressure.

Model Change(s):

The following change was made to the cutset files:

- 2RHSYSTARTA----- (RH TRAIN A IS PLACED INTO OPERATION FOLLOWING A TRANSIENT): Probability changed to 0.0.
- 2RHSYSTARTB----- (RH TRAIN B IS PLACED INTO OPERATION FOLLOWING A TRANSIENT): Probability changed to 0.0.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.39E-06	7.08	$53,132
Percent Change	7.4%	0.4%	0.4%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,222
H/E	5.93E-08	5.72E-08	3.14E-01	3.03E-01	$2,763	$2,666
H/I	1.90E-08	1.90E-08	1.08E-01	1.08E-01	$954	$954
M/E	2.14E-07	2.12E-07	1.58E+00	1.57E+00	$9,395	$9,307
M/I	9.27E-07	9.26E-07	3.58E+00	3.57E+00	$32,723	$32,688
L/E	3.88E-07	3.85E-07	8.57E-02	8.51E-02	$124	$123
L/I	1.45E-07	1.42E-07	1.03E-01	1.01E-01	$177	$173
INTACT	7.45E-07	5.70E-07	1.62E-03	1.24E-03	$1	$0
Total	2.58E-06	2.39E-06	7.11E+00	7.08E+00	$53,358	$53,132

Applying the process described in Section F.4 yields an internal events cost-risk of $1,077,666. After accounting for “round up” of the base internal events cost-risk, this value is $1,078,483. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$1,078,483 * 5.2 = \$5,608,112$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 7 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
LSCS Unit 2	$5,657,600	$5,608,112	$49,488

Based on a $962,403 cost of implementation for LSCS, the net value for this SAMA is -$912,915 ($49,488 - $962,403), which indicates this SAMA is not cost-beneficial.

F.6.8 SAMA 8: OBTAIN A 480V AC PORTABLE GENERATOR TO SUPPLY THE 125V DC BATTERY CHARGERS AND PROCEDURALIZE ITS USE

For long term SBO scenarios, the hardened containment vent that LSCS is committed to install will provide a reliable means of containment heat removal, but the PRA analysis assumes that the battery life is currently limited to about 7 hours. After battery depletion, the SRVs will close and the RPV will re-pressurize and prevent injection with a low pressure system, such as the fire protection system. Use of a portable generator to provide power to the 125V DC battery chargers would provide a means of maintaining the SRVs open, energize critical instrumentation, and ensure RPV pressure remains low enough for use of low pressure alternate makeup systems.

This SAMA will address many SBO contributors, but some of the largest SBO events are related to internal flooding events initiated in the fire protection system. The fire protection flooding events are addressed by SAMAs 9 and 11.

Assumptions:

Flow from the fire protection system, in its current configuration, is only adequate in cases where RCIC has initially successfully operated. This injection system is not available in fire protection flooding events.

The benefit provided by this SAMA in non-long term SBO scenarios is small compared to the benefit from long term SBO scenarios and can be neglected for this analysis.

While the portable generator could support RCIC for longer periods of time, it is assumed that the diesel fire pump is required to place the plant in a stable state.

It is assumed that procedures direct the alignment of the 480V AC generator in scenarios where battery depletion is projected to occur, that RPV makeup with the diesel fire pump is directed to be aligned before containment failure, and that level can be controlled from outside the turbine building by either throttling a valve or by cycling the diesel fire pump (injection system is not impacted by containment vent path failure).

PRA Model Changes to Model SAMA:

The 480V AC generator capability has been approximated by adding the diesel fire pump as a low pressure injection source for SBO scenarios in which ADS and RCIC are initially successful.

In addition, a lumped event was added to represent the 480V AC power source that feeds the division 1 battery chargers.

Model Change(s):

The following modeling changes were made:

- Gate FPS-VNT (FIRE PROTECTION SYSTEM FAILURE GIVEN VENT CHALLENGE) added to the following gates: DLOP-025P, DLOP-028P, DLOP-030P, LOOP-025P, LOOP-028P, LOOP-030P, TBFLD-008P, TBFLD-010P, TBFLD-013P, TBFLD-015P, and TBFLD-016P.
- Created event SAMA8 (FAILURE OF 480V AC GENERATOR POWER): New basic with a failure probability of 5.0E-02 to represent hardware and human error related failure contributors for the use of the 480V AC generator.
- Created gate SAMA8-GATE: New AND gate including existing gate 2AP19E-PWR and new event SAMA8.
- Under gate 2AP73E-CHR-AC (LOSS OF POWER FROM MCC BUS 235X-3 TO U2 DIV1 CHARGERS): Deleted gate 2AP19E-PWR and added gate SAMA8-GATE
- Created gate SAMA8-GATE-CHRGR: New AND gate including existing gate 241Y-235X-PATH and new event SAMA8.
- Under gate 2AP73E-CHRGR (LOSS OF POWER FROM MCC BUS 235X-3 TO U2 DIV1 CHARGERS): Deleted gate 241Y-235X-PATH and added gate SAMA8-GATE-CHRGR.
- Created gate SAMA8-GATE-GL: New AND gate including existing gate 2AP19E-PWR-FLD and new event SAMA8.
- Under gate 2AP73E-CHR-AC-FL (LOSS OF MCC BUS 235X-3 TO U2 DIV1 CHARGERS FOR EARLY TB-RB-FLD): Deleted gate 2AP19E-PWR-FLD and added gate SAMA8-GATE-GL.

The recovery tree was merged with the updated fault tree logic in order to ensure the recovery logic includes the changes from the SAMA modifications.

<u>Results of SAMA Quantification:</u>

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.47E-06	6.83	$51,022
Percent Change	4.3%	3.9%	4.4%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,222
H/E	5.93E-08	5.88E-08	3.14E-01	3.11E-01	$2,763	$2,740
H/I	1.90E-08	4.74E-09	1.08E-01	2.68E-02	$954	$238
M/E	2.14E-07	2.13E-07	1.58E+00	1.57E+00	$9,395	$9,351
M/I	9.27E-07	8.84E-07	3.58E+00	3.41E+00	$32,723	$31,205
L/E	3.88E-07	3.88E-07	8.57E-02	8.57E-02	$124	$124
L/I	1.45E-07	1.16E-07	1.03E-01	8.22E-02	$177	$142
INTACT	7.45E-07	7.20E-07	1.62E-03	1.56E-03	$1	$1
Total	2.58E-06	2.47E-06	7.11E+00	6.83E+00	$53,358	$51,022

Applying the process described in Section F.4 yields an internal events cost-risk of $1,040,608. After accounting for “round up” of the base internal events cost-risk, this value is $1,041,425. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$1{,}041{,}425 * 5.2 = \$5{,}415{,}410$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 8 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
LSCS Unit 2	$5,657,600	$5,415,410	$242,190

Based on a $400,000 cost of implementation for LSCS, the net value for this SAMA is -$157,810 ($242,190 - $400,000), which indicates this SAMA is not cost-beneficial.

F.6.9 SAMA 9: DEVELOP FLOOD ZONE SPECIFIC PROCEDURES

Many plants have analyzed internal flooding scenarios and have developed procedures that include guidance to identify flood sources and locations by using existing instrumentation related to pressures, flows, and sump alarms. Based on the flood source/location, the procedures direct specific actions to both terminate the flooding event and to mitigate the impacts of the flooding event (e.g., provide alternate cooling for systems that may have lost their normal cooling source).

For LSCS, the reliability of the internal flood mitigation actions could be improved by developing these types of location and system specific flood response procedures. For example, for fire protection floods in the reactor building, developing procedures that direct the isolation of the FP070 and FP080 valves could significantly reduce the time required to terminate reactor building floods from the fire protection system. Increasing the time margin for the operators to respond to the floods would improve the likelihood of preventing damage to critical ECCS equipment.

<u>Assumptions:</u>

The procedures will completely eliminate the risk of flooding events.

<u>PRA Model Changes to Model SAMA:</u>

To approximate the impact of this SAMA, the initiating event frequencies for flooding events were set to 0.0 in the cutsets.

Model Change(s):

The following initiating events were set to 0.0 in the cutsets:

- %FSAB1, %FSAB2, %FSDG1, %FSDG2, %FSRB1 0.0, %FSRB10, %FSRB11, %FSRB12, %FSRB2, %FSRB3, %FSRB4, %FSRB5, %FSRB6, %FSRB7 , %FSRB8, %FSRB9, %FSTB1, %FSTB10, %FSTB11, %FSTB2, %FSTB3, %FSTB4, %FSTB5, %FSTB6, %FSTB7

<u>Results of SAMA Quantification:</u>

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	**Dose-Risk**	**OECR**
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.35E-06	6.88	$51,580
Percent Change	8.9%	3.2%	3.3%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,222
H/E	5.93E-08	5.92E-08	3.14E-01	3.13E-01	$2,763	$2,759
H/I	1.90E-08	1.71E-08	1.08E-01	9.68E-02	$954	$858
M/E	2.14E-07	2.12E-07	1.58E+00	1.57E+00	$9,395	$9,307
M/I	9.27E-07	8.84E-07	3.58E+00	3.41E+00	$32,723	$31,205
L/E	3.88E-07	3.87E-07	8.57E-02	8.55E-02	$124	$123
L/I	1.45E-07	8.60E-08	1.03E-01	6.10E-02	$177	$105
INTACT	7.45E-07	6.20E-07	1.62E-03	1.35E-03	$1	$1
Total	2.58E-06	2.35E-06	7.11E+00	6.88E+00	$53,358	$51,580

Applying the process described in Section F.4 yields an internal events cost-risk of $1,047,209. After accounting for "round up" of the base internal events cost-risk, this value is $1,048,026. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$1,048,026 * 5.2 = \$5,449,735$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 9 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
LSCS Unit 2	$5,657,600	$5,449,735	$207,865

Based on a $115,000 cost of implementation for LSCS, the net value for this SAMA is $92,865 ($207,865 - $115,000), which indicates this SAMA is potentially cost-beneficial.

F.6.10 SAMA 10: CHANGE THE LOGIC TO CLOSE THE TURBINE DRIVEN FEEDWATER PUMP DISCHARGE VALVES WHEN THE PUMPS ARE NOT RUNNING

In cases where the turbine driven FW pumps are tripped or are malfunctioning, it is currently necessary to manually isolate the pump discharge valves to prevent hotwell depletion and/or

RPV overfill when RPV pressure is reduced. Failure to control the valves can make the hotwell unavailable as a suction source for other injection systems or flood the steam lines, which may lead to the unavailability of RCIC. Changing the system logic to automatically close the valves when the pumps trip or are not running would reduce the likelihood of uncontrolled injection (no RPV overfill from the Condensate/CB pumps when pressure is reduced).

Assumptions:

This SAMA completely eliminates the contributions from failing to isolate the turbine driven pump discharge valves after pump trip/failure.

No credit is taken for manual isolation of the valves in the event that auto isolation fails.

PRA Model Changes to Model SAMA:

The human failure event associated with closing the turbine driven feedwater pump discharge valves was changed to a new event with a failure probability of 1.0E-04. This reduces the independent contribution of the isolation failure and precludes the generation of dependent human error combination including the operator action to isolate the valves.

Model Change(s):

The following changes were made to the main fault tree and recovery tree:

- 2FWOPMOV10AB-H-- (HEP (REC): OPERATOR FAILS TO CLOSE THE TDRFP DISCHARGE MOVS 2FW010A & B): Basic event ID changed to "SAMA10" and assigned a probability of 1.0E-04.
- 2FWOP10ABQUV-H-- (HEP: OP FAILS TO CLOSE TDRFP MOVs 10A & B (COND PROB - QUV)): Basic event ID changed to "SAMA-10L" and assigned a probability of 0.0 (not relevant for automated function).

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.35E-06	5.65	$41,251
Percent Change	8.9%	20.5%	22.7%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,222
H/E	5.93E-08	5.40E-08	3.14E-01	2.86E-01	$2,763	$2,516
H/I	1.90E-08	1.75E-08	1.08E-01	9.91E-02	$954	$879
M/E	2.14E-07	1.63E-07	1.58E+00	1.20E+00	$9,395	$7,156
M/I	9.27E-07	6.57E-07	3.58E+00	2.54E+00	$32,723	$23,192
L/E	3.88E-07	3.59E-07	8.57E-02	7.93E-02	$124	$115
L/I	1.45E-07	1.40E-07	1.03E-01	9.93E-02	$177	$171
INTACT	7.45E-07	8.80E-07	1.62E-03	1.91E-03	$1	$1
Total	2.58E-06	2.35E-06	7.11E+00	5.65E+00	$53,358	$41,251

Applying the process described in Section F.4 yields an internal events cost-risk of $854,868. After accounting for "round up" of the base internal events cost-risk, this value is $855,685. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$855{,}685 * 5.2 = \$4{,}449{,}562$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 10 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
LSCS Unit 2	$5,657,600	$4,449,562	$1,208,038

Based on a $260,219 cost of implementation for LSCS, the net value for this SAMA is $947,819 ($1,208,038 - $260,219), which indicates this SAMA is potentially cost-beneficial.

F.6.11 SAMA 11: PROVIDE THE CAPABILITY TO TRIP THE FPS PUMPS FROM THE MCR

The reliability of the internal flood mitigation actions could be improved by providing the capability to trip the fire protection system pumps from the MCR. Currently, is it is necessary to for an operator to travel to the Lake Screen House to locally trip the fire protection pumps to eliminate that system's flow. Increasing the time margin for the operators to respond to the floods would improve the likelihood of preventing damage to critical ECCS equipment. It is assumed that this change would be accompanied by a procedure update that would include directions to remotely isolate valves for service water isolation (e.g., 0FP070 and 0FP080) to ensure that the time benefits associated with the MCR pump control switches are fully realized.

Assumptions:

The HEP associated with the action to trip the FPS pumps is dominated by the time reliability curve contribution to the cognitive component of the HEP. Installation of pump controls in the MCR and directing isolation of service water using controls in the MCR is assumed to reduce the manipulation time to 2 minutes; 1 minute total to trip the two pumps and 1 minute total to isolate service water from the fire protection system header. This would reduce the manipulation time from 16 minutes to about 2 minutes, which results in a diagnosis time of 19 minutes. The time reliability curve contribution for this diagnosis time is 3.2E-02. The execution contributions and cause based decision tree contributions would increase the total HEP, but for this analysis, the total HEP for this action is assumed to be 3.2E-02.

PRA Model Changes to Model SAMA:

The human failure event associated with tripping the fire protection pumps and isolating the service water system from the fire protection header is not used in any dependent operator action combinations, so this SAMA was modeled by changing the basic event probability for the operator action in the cutsets.

Model Change(s):

The following changes were made to the cutsets:

- 2FPOPMANTRIP1H-- (HEP: OPERATOR FAILS TO TRIP FPS FOR FPS BREAK (SHORT TIME FRAME)): Basic probability changed to 3.2E-02.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	**Dose-Risk**	**OECR**
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.54E-06	7.09	$53,219
Percent Change	1.6%	0.3%	0.3%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,222
H/E	5.93E-08	5.92E-08	3.14E-01	3.13E-01	$2,763	$2,759
H/I	1.90E-08	1.87E-08	1.08E-01	1.06E-01	$954	$939
M/E	2.14E-07	2.14E-07	1.58E+00	1.58E+00	$9,395	$9,395
M/I	9.27E-07	9.24E-07	3.58E+00	3.57E+00	$32,723	$32,617
L/E	3.88E-07	3.88E-07	8.57E-02	8.57E-02	$124	$124
L/I	1.45E-07	1.34E-07	1.03E-01	9.50E-02	$177	$163
INTACT	7.45E-07	7.20E-07	1.62E-03	1.56E-03	$1	$1
Total	2.58E-06	2.54E-06	7.11E+00	7.09E+00	$53,358	$53,219

Applying the process described in Section F.4 yields an internal events cost-risk of $1,083,394. After accounting for "round up" of the base internal events cost-risk, this value is $1,084,211. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$1,084,211 * 5.2 = \$5,637,897$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 11 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
LSCS Unit 2	$5,657,600	$5,637,897	$19,703

Based on a $217,415 cost of implementation for LSCS, the net value for this SAMA is -$197,712 ($19,703 - $217,415), which indicates this SAMA is not cost-beneficial.

F.6.12 SAMA 12: CROSSITIE THE HPCS AND FW INJECTION LINES FOR ATWS MITIGATION

The use of HPCS is not allowed for ATWS due to reactivity issues, but installing a cross-tie between the HPCS and FW injection lines would provide another means of supplying high pressure injection to the RPV in ATWS scenarios.

This SAMA makes use of an existing injection system (HPCS) to provide an additional means of high pressure injection in ATWS scenarios. The other potential benefit would be to use the cross-tie to bypass HPCS injection valve failures, which are not significant contributors to risk. In order to provide a simplified, bounding assessment of benefit this SAMA, it was assumed that this SAMA eliminates the contribution of all ATWS events. This was accomplished by setting the accident class IV flag (RCVCL-4A) to 0.0 in the cutsets.

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.09E-06	5.63	$44,593
Percent Change	19.0%	20.8%	16.4%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,222
H/E	5.93E-08	4.09E-08	3.14E-01	2.16E-01	$2,763	$1,906
H/I	1.90E-08	1.90E-08	1.08E-01	1.08E-01	$954	$954
M/E	2.14E-07	3.60E-08	1.58E+00	2.66E-01	$9,395	$1,580
M/I	9.27E-07	9.27E-07	3.58E+00	3.58E+00	$32,723	$32,723
L/E	3.88E-07	9.50E-08	8.57E-02	2.10E-02	$124	$30
L/I	1.45E-07	1.45E-07	1.03E-01	1.03E-01	$177	$177
INTACT	7.45E-07	7.40E-07	1.62E-03	1.61E-03	$1	$1
Total	2.58E-06	2.09E-06	7.11E+00	5.63E+00	$53,358	$44,593

Applying the process described in Section F.4 yields an internal events cost-risk of $897,389. After accounting for "round up" of the base internal events cost-risk, this value is $898,206. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$898{,}206 * 5.2 = \$4{,}670{,}671$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 12 Bounding Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
LSCS Unit 2	$5,657,600	$4,670,671	$986,929

Based on a $4,401,674 cost of implementation for LSCS, the net value for this SAMA is -$3,414,745 ($986,929 - $4,401,674), which indicates this SAMA is not cost-beneficial.

F.6.13 SAMA 14: PROVIDE A PORTABLE DC SOURCE TO SUPPORT RCIC AND SRV OPERATION

For scenarios with 125V DC bus faults, providing a means for a portable generator with DC output to supply 125V ESF DC distribution panel 1(2)11Y would support RCIC operation and long term SRV operation with Fire Protection System injection.

<u>Assumptions:</u>

DC bus failure initiating events will likely require rapid response to address loss of makeup. It is assumed that the required electric cables for the generator are pre-staged such that the generator can be wheeled into position, started and connected via simple actions.

Flow from the fire protection system, in its current configuration, is only adequate in cases where RCIC can be re-started after DC power alignment.

Fire protection system injection is not available in fire protection flooding events.

While the portable generator could support RCIC for longer periods of time, it is assumed that the diesel fire pump is required to place the plant in a stable state.

The procedures directing the alignment of the generator also direct subsequent alignment of the fire protection system such that it is available for RPV makeup when RPV depressurization is eventually required due to lack of suppression pool cooling.

The diesel fire pump is directed to be aligned before containment failure, and that level can be controlled from outside the turbine building by either throttling a valve or by cycling the diesel fire pump (injection system is not impacted by containment vent path failure).

PRA Model Changes to Model SAMA:

The DC generator capability has been approximated by adding the diesel fire pump as a low pressure injection source for SBO scenarios in which ADS and RCIC are initially successful. In addition, a lumped event was added to represent the 480V AC power source that feeds the division 1 battery chargers.

Model Change(s):

The following modeling changes were made:

- Gate FPS-VNT (FIRE PROTECTION SYSTEM FAILURE GIVEN VENT CHALLENGE) added to the following gates: DLOP-025P, DLOP-028P, DLOP-030P, LOOP-025P, LOOP-028P, LOOP-030P, TBFLD-008P, TBFLD-010P, TBFLD-013P, TBFLD-015P, and TBFLD-016P.
- Created event SAMA14 (FAILURE OF DC GENERATOR POWER): New basic with a failure probability of 5.0E-02 to represent hardware and human error related failure contributors for the use of the DC generator.
- Created gate SAMA14-AC: New AND gate including existing gate 2DC08E-PWR-AC and new event SAMA14.
- Under gate 2DC11E-PWR-AC (FAULTS AFFECTING POWER FROM DC BUS 2DC11E): Deleted gate 2DC08E-PWR-AC and added gate SAMA14-AC
- Created gate SAMA14-G: New AND gate including existing gate 2DC08E-PWR and new event SAMA14.
- Under gate 2DC11E-PWR (FAULTS AFFECTING POWER FROM DC BUS 2DC11E): Deleted gate 2DC08E-PWR and added gate SAMA14-G.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.35E-06	6.64	$49,422
Percent Change	8.9%	6.6%	7.4%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,222
H/E	5.93E-08	5.15E-08	3.14E-01	2.72E-01	$2,763	$2,400
H/I	1.90E-08	4.40E-09	1.08E-01	2.49E-02	$954	$221
M/E	2.14E-07	2.12E-07	1.58E+00	1.57E+00	$9,395	$9,307
M/I	9.27E-07	8.51E-07	3.58E+00	3.28E+00	$32,723	$30,040
L/E	3.88E-07	3.34E-07	8.57E-02	7.38E-02	$124	$107
L/I	1.45E-07	1.03E-07	1.03E-01	7.30E-02	$177	$126
INTACT	7.45E-07	7.10E-07	1.62E-03	1.54E-03	$1	$1
Total	2.58E-06	2.35E-06	7.11E+00	6.64E+00	$53,358	$49,422

Applying the process described in Section F.4 yields an internal events cost-risk of $1,007,535. After accounting for "round up" of the base internal events cost-risk, this value is $1,008,352. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$1{,}008{,}352 * 5.2 = \$5{,}243{,}430$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 14 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
LSCS Unit 2	$5,657,600	$5,243,430	$414,170

Based on a $489,277 cost of implementation for LSCS, the net value for this SAMA is -$75,107 ($414,170 - $489,277), which indicates this SAMA is not cost-beneficial.

F.6.14 SAMA 15: TIE RHRSW TO THE LPCS SYSTEM FOR ISLOCA MITIGATION

Interfacing systems LOCA (ISLOCA) events are dominated by isolation failures in which there are no long term RPV makeup sources. Providing a hard pipe connection with manual valves between the RHRSW system and the LPCS system would provide a source of makeup to the RPV for cases in which RPV depressurization is available.

Because manual valves are used for this cross-tie to reduce costs, this SAMA provides the capability to mitigate most ISLOCA events because in a high percentage of cases, an injection source is available for RCS makeup until the water source is depleted. By the time the water source is depleted, the local actions to align RHRSW to LPCS can be completed.

<u>Assumptions:</u>

The action to align the cross-tie occurs in the reactor building, but for core damage prevention, it can be performed before the deposition of any RPV inventory in to the reactor building makes the environment inhospitable.

The hardware associated with the use of the RHRSW-LPCS x-tie is not impacted by the reactor building environment.

The breaks outside containment (BOC) and ISLOCA rupture events are large enough to depressurize the RPV to allow low pressure injection without ADS. The ISLOCA leak events require ADS.

For the credited BOC and ISLOCA events, HPCS and/or LPCI provide initial makeup using available inventory sources. These systems are not included in the baseline logic and in most cases would be available for initial injection. This is not necessarily true for other LOCA contributors and no credit is taken for medium or larger LOCAs.

Post core damage alignment of the RHRSW-LPCS cross-tie can be performed to help prevent RPV meltthrough, drywell failure, debris cooling and to perform containment flooding.

Not credited for ATWS due to alignment time limitations.

The hardware modification was designed to use flow from at least two RHRSW pumps, but one pump is required for success in the SAMA model (to maximize benefit).

The HFE for aligning the cross-tie was treated as an independent event.

PRA Model Changes to Model SAMA:

The inclusion of the RHRSW-LPCS cross-tie required changes to both the main fault tree and the recovery fault tree. The cross-tie was assumed to require the LPCS injection path (existing logic from the LPCS system) and the availability of the RHRSW pumps (existing logic from the RHRSW system). ISLOCAs in the LPCS line were included as failure for the cross tie, as was an event representing the failure to align the cross-tie. The cross-tie logic was added at the sequence level for BOC and ISLOCA sequences where credit was not previously taken for any low pressure injection systems. The logic was also added to the existing fault tree structure in scenarios where venting or containment failure resulted in the loss of injection systems.

Model Change(s):

The following change was made to the main fault tree:

- Created new basic event SAMA15 (FAILURE TO ALIGN RHRSW-LPCS X-TIE): Probability set to 1.0E-03.
- Created new gate SAMA15-G1: OR gate including the following inputs:
    - Existing gate LPCS-PMP-ISOL
    - Existing gate RHRA-SW-FAILURE
    - Existing event %ISLOCA-LPCS
    - Existing event %R
    - Existing gate LLOCA
    - Existing gate IE-MLOCA
    - SCRAM-FAILS
    - New event SAMA15
- Created new OR gate SAMA15-G2 with the following inputs:
    - Existing gate ADS
    - New gate SAMA15-G1.
- Added gate SAMA15-G1 to the following gates:
    - BOC-003P

- ILOC-006P
- ILOC-009P
- CTFAIL-MU-LPI
- VENT-MU-LPI
- LPCI-LPCS

- Added gate SAMA15-G2 to:
  - Gate ILOC-002P
  - Gate ILOC-008P
- Under existing gate BOC-002P:
  - Deleted gate HP-CS-LPI-BOC
  - Added new OR gate BOC-002-SAMA15
- Created new gate OR BOC-002-SAMA15 to preclude credit for SAMA 15 in this BOC sequence where early injection fails. Includes the following inputs:
  - New AND gate BOC-002-SAMA15-G2
  - Existing event 2SY--VENT1---FCC
- Created new AND gate BOC-002-SAMA15-G2 with the following inputs:
  - Existing gate LPCI
  - Existing gate LPCS
  - Existing gate HPCS
- Created new OR gate SAMA15-G1-L2 with the following inputs (to allow post core damage credit for LOCA and ATWS cases):
  - Existing gate LPCS-PMP-ISOL
  - Existing gate RHRA-SW-FAILURE
  - Existing event %ISLOCA-LPCS
  - New event SAMA15
- Added new OR gate SAMA15-G1-L2 to:
  - RX2HRDFLR-ALTINJ (HARDWARE FAILURE OF ALTERNATE INJECTION SYSTEMS)
  - RX10RDFLR-ALTINJ (HARDWARE FAILURE OF ALTERNATE INJECTION SYSTEMS)
  - RX12RDFLR-ALTINJ (HARDWARE FAILURE OF ALTERNATE INJECTION SYSTEMS)
  - RX13RDFLR-ALTINJ (HARDWARE FAILURE OF ALTERNATE INJECTION SYSTEMS)
  - FC-HRDFLR-EXTSRC (HARDWARE FAILURE OF EXTERNAL SOURCES)
  - FC-HRDFLR-EXTSRC-SBO (HARDWARE FAILURE OF EXTERNAL SOURCES)

The recovery tree was merged with the updated fault tree logic in order to ensure the recovery logic includes the changes from the SAMA modifications.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	**Dose-Risk**	**OECR**
Base Value	2.58E-06	7.11	$53,358
SAMA Value	1.62E-06	3.06	$22,870
Percent Change	37.2%	57.0%	57.1%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.49E-09	1.34E+00	1.37E-01	$7,222	$737
H/E	5.93E-08	4.92E-08	3.14E-01	2.60E-01	$2,763	$2,293
H/I	1.90E-08	1.73E-08	1.08E-01	9.79E-02	$954	$868
M/E	2.14E-07	1.34E-07	1.58E+00	9.90E-01	$9,395	$5,883
M/I	9.27E-07	3.63E-07	3.58E+00	1.40E+00	$32,723	$12,814
L/E	3.88E-07	3.71E-07	8.57E-02	8.20E-02	$124	$118
L/I	1.45E-07	1.28E-07	1.03E-01	9.08E-02	$177	$156
INTACT	7.45E-07	5.49E-07	1.62E-03	1.19E-03	$1	$0
Total	2.58E-06	1.62E-06	7.11E+00	3.06E+00	$53,358	$22,870

Applying the process described in Section F.4 yields an internal events cost-risk of $480,477. After accounting for “round up” of the base internal events cost-risk, this value is $481,294. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$481,294 * 5.2 = \$2,502,729$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 15 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
LSCS Unit 2	$5,657,600	$2,502,729	$3,154,871

Based on a $1,370,000 cost of implementation for LSCS, the net value for this SAMA is $1,784,871 ($3,154,871 - $1,370,000), which indicates this SAMA is potentially cost-beneficial.

F.6.15 SAMA 16: PROVIDE PORTABLE FANS FOR ALTERNATE ROOM COOLING IN THE CORE STANDBY COOLING SYSTEM VAULTS

Pump cubicle cooling fan or damper failures can result in the failure of the pumps in the Core Standby Cooling System vaults after heat up. Providing portable fans (and potentially temporary ductwork) could prevent failure by providing a temporary, alternate source of cubicle cooling. Room heat up calculations would be required as part of this effort to demonstrate that the portable fans could provide adequate cooling.

Assumptions:

The model includes an action to manually initiate CSCS cooling if automatic initiation fails. No credit is taken to align alternate room cooling if the action to manually initiate the existing HVAC system fails after auto initiation failure.

This SAMA is assumed to completely eliminate room cooling hardware failures.

PRA Model Changes to Model SAMA:

The alternate CSCS room cooling capability has been approximated by deleting the gates associated with room cooling failures (excluding the automatic initiation failures, which are already addressed in the model).

Model Change(s):

The following modeling changes were made to the main and recovery fault trees:

- Gate CSCS-RM-1X (UNIT 1 CSCS DIV 1 PUMP ROOM COOLING FAILS): Deleted.
- Gate CSCS-RM-1 (UNIT 2 CSCS DIV 1 ROOM COOLING FAILS): Deleted.
- Gate CSCS-RM-2X (UNIT 1 CSCS DIV. 2 ROOM COOLING FAILS): Deleted.
- Gate CSCS-RM-2 (UNIT 2 CSCS DIV 2 ROOM COOLING FAILS): Deleted.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.23E-06	6.24	$45,595
Percent Change	13.6%	12.2%	14.5%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,223
H/E	5.93E-08	5.92E-08	3.14E-01	3.13E-01	$2,763	$2,759
H/I	1.90E-08	1.40E-08	1.08E-01	7.92E-02	$954	$703
M/E	2.14E-07	2.10E-07	1.58E+00	1.55E+00	$9,395	$9,219
M/I	9.27E-07	7.20E-07	3.58E+00	2.78E+00	$32,723	$25,416
L/E	3.88E-07	3.77E-07	8.57E-02	8.33E-02	$124	$120
L/I	1.45E-07	1.27E-07	1.03E-01	9.00E-02	$177	$155
INTACT	7.45E-07	6.40E-07	1.62E-03	1.39E-03	$1	$1
Total	2.58E-06	2.23E-06	7.11E+00	6.24E+00	$53,358	$45,595

Applying the process described in Section F.4 yields an internal events cost-risk of $934,652. After accounting for “round up” of the base internal events cost-risk, this value is $935,469. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$935,469 * 5.2 = \$4,864,439$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 16 Averted Cost-Risk			
Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
LSCS Unit 2	$5,657,600	$4,864,439	$793,161

Based on a $475,000 cost of implementation for LSCS, the net value for this SAMA is $318,161 ($793,161 - $475,000), which indicates this SAMA is potentially cost-beneficial.

F.6.16 SAMA 18 IMPROVE THE CONNECTION BETWEEN THE FIRE PROTECTION AND FEEDWATER SYSTEMS

For SBO cases with failure of RCIC, aligning the fire protection system to the feedwater system using fire hoses cannot prevent core damage, primarily due to a lengthy alignment time. This time could be reduced by providing a hard pipe connection between the two systems. If a permanent connection between the systems is undesirable, a short, flexible connecting hose could potentially be maintained out of the flowpath provided that rapid alignment could be demonstrated.

<u>Assumptions:</u>

The improved hard pipe connection reduces alignment time such that fire water can be aligned in time to mitigate loss of all injection scenarios.

Even with the RPV depressurized and a hard pipe connection to the RPV, elevation differences may present pressure challenges that would limit injection flow such that it would be inadequate in cases where all injection fails at the time of the initiating event. However, it is assumed that this SAMA will allow fire protection to be used to prevent core damage even when injection from other sources is lost at the time of the initiating event.

No credit is taken for the fire water makeup alignment for scenarios involving loss of inventory from the RPV via LOCAs, IORV events, or leakage after water hammer events. The exception is for ISLOCAs that have been isolated and for the un-isolated ISLOCA leaks (but not ruptures) where the makeup requirements are low.

The short time frame associated with aligning fire protection for injection in cases where other injection systems have failed is likely a non-negligible contributor, but the action to align fire water in these scenarios is assumed to be 100% reliable.

The existing logic for aligning the fire protection system for injection post venting or containment failure includes alignment errors. One event represents the failure to align injection under nominal conditions and another represents the impact of hash environment on the alignment.

The installation of the hard pipe connection is assumed to eliminate the nominal alignment action, but the failure associated with harsh environmental conditions was retained.

The hard pipe connection is not assumed to provide any additional benefit for post core damage conditions.

The fire protection system is not seismically qualified, but credit is taken for its use in seismic events to conservatively show an increased benefit for the SAMA.

<u>PRA Model Changes to Model SAMA:</u>

The fault tree was updated to credit the fire protection system in the places where LPCI and LPCS are credited, but the system is failed for the LOCA and IORV initiating event and for water hammer scenarios. In addition, the logic was changed to include the fire protection system injection capability in the early SBO scenarios in which ADS is available for those sequences not impact by the LPCS-LPCI gate.

<u>Model Change(s):</u>

The following changes were made to the fault tree:

- Created new OR gate SAMA18-G1: This gate includes the following existing events and gates:
  - Gate FPS-FAILURE (FIRE PROTECTION SYSTEM FAILURE)
  - Gate IE-SLOCA (SMALL LOCA INITIATING EVENT)
  - Gate LOCA-NOT-S2 (LOCA INITIATORS GREATER THAN SLOCA)
  - Initiating event %TI (INADVERTENTLY OPEN RELIEF VALVE INITIATING EVENT)
  - Basic event 2RHSYLEAKA---L-- (RH TRAIN A FAILS DUE TO EXCESSIVE LEAKAGE FOLLOWING WATER HAMMER)
  - Basic event 2RHSYARUPTFLOOD- (RH TRAIN A WATER HAMMER INDUCED RUPTURE CAUSES FLOODING)
  - Basic event 2RHSYLEAKB---L-- (2RHSYLEAKB---L--
  - Basic event 2RHSYRUPTUREBR-- (RH TRAIN B FAILS DUE TO RUPTURE FOLLOWING WATER HAMMER)
  - Gate SCRAM-FAILS
- Created new OR gate SAMA18-G2: This gate includes the following existing events and gates:
  - Gate FPS-FAILURE (FIRE PROTECTION SYSTEM FAILURE)
  - ADS
- Added new OR gate SAMA18-G1 under the following gates:

- Existing gate LPCI-LPCS
- Existing gate LPI-TBRB-FLD
- Existing gate LPI-FSTB

- Deleted event 2FPOPALGNFPSAH-- (HEP: OPERATOR FAILS TO ALIGN FPS FOLLOWING CONTAINMENT VENT OR FAILURE)
- Added new OR gate SAMA18-G2 under the following gates:
  - ILOC-002P
  - ILOC-008P
- Added existing gate FPS-FAILURE under gate ILOC-006P.

The recovery tree was merged with the updated fault tree logic in order to ensure the recovery logic includes the changes from the SAMA modifications.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.36E-06	6.48	$47,858
Percent Change	8.5%	8.9%	10.3%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	Dose-$Risk_{BASE}$	Dose-$Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,223
H/E	5.93E-08	5.68E-08	3.14E-01	3.00E-01	$2,763	$2,647
H/I	1.90E-08	9.60E-09	1.08E-01	5.43E-02	$954	$482
M/E	2.14E-07	2.09E-07	1.58E+00	1.54E+00	$9,395	$9,175
M/I	9.27E-07	7.95E-07	3.58E+00	3.07E+00	$32,723	$28,064
L/E	3.88E-07	3.58E-07	8.57E-02	7.91E-02	$124	$114
L/I	1.45E-07	1.25E-07	1.03E-01	8.86E-02	$177	$153
INTACT	7.45E-07	7.23E-07	1.62E-03	1.57E-03	$1	$1
Total	2.58E-06	2.36E-06	7.11E+00	6.48E+00	$53,358	$47,858

Applying the process described in Section F.4 yields an internal events cost-risk of $979,475. After accounting for "round up" of the base internal events cost-risk, this value is $980,292. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{\text{SAMA}} = \$980{,}292 * 5.2 = \$5{,}097{,}518$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 18 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
LSCS Unit 2	$5,657,600	$5,097,518	$560,082

Based on a $649,194 cost of implementation for LSCS, the net value for this SAMA is -$89,112 ($560,082 - $649,194), which indicates this SAMA is not cost-beneficial.

F.6.17 SAMA 19: PROVIDE REMOTE ALIGNMENT CAPABILITY OF RHRSW TO THE LPCS SYSTEM FOR LOCA MITIGATION

For some LOCA scenarios, CCF plugging of the ECCS suction strainers can fail all ECCS injection. Providing the operators with the ability to cross-tie the RHRSW system to the LPCS system from the MCR would provide a source of makeup to the RPV for cases in which RPV depressurization is available. While more costly than the manual cross-tie evaluated in SAMA 15, the ability to align the cross-tie from the MCR is essential because of the limited time that is available to mitigate the LOCA events (no injection sources available).

In addition, it could potentially serve as a mitigating feature for some post core damage phenomena, such as preventing RPV meltthrough; however, the availability of such a system would generally preclude core damage and the conditions under which it would provide this type of benefit would be limited.

Assumptions:

The action to align the cross-tie occurs in the main control room and can be performed in the time range of 5 minutes and can be used in any scenario in which LPCS is currently credited.

The hardware associated with the use of the RHRSW-LPCS x-tie is not impacted by the reactor building environment.

The breaks outside containment (BOC) and ISLOCA rupture events are large enough to depressurize the RPV to allow low pressure injection without ADS. The ISLOCA leak events require ADS.

The hardware modification was designed to use flow from at least two RHRSW pumps, but one pump is required for success in the SAMA model (to maximize benefit).

The HFE for aligning the cross-tie was treated as an independent event.

<u>PRA Model Changes to Model SAMA:</u>

The inclusion of the RHRSW-LPCS cross-tie required changes to both the main fault tree and the recovery fault tree. The cross-tie was assumed to require the LPCS injection path (existing logic from the LPCS system) and the availability of the RHRSW pumps (existing logic from the RHRSW system). ISLOCAs in the LPCS line were included as failure for the cross tie, as was an event representing the failure to align the cross-tie. The cross-tie logic was added at the sequence level for BOC and ISLOCA sequences where credit was not previously taken for any low pressure injection systems. The logic was also added to the existing fault tree structure in scenarios where venting or containment failure resulted in the loss of injection systems.

<u>Model Change(s):</u>

The following change was made to the main fault tree:

- Created new basic event SAMA19 (FAILURE TO ALIGN RHRSW-LPCS X-TIE): Probability set to 1.0E-03.
- Created new OR gate SAMA19-G1 with the following inputs:
    - Existing gate LPCS-PMP-ISOL
    - Event %ISLOCA-LPCS
    - Existing gate RHRA-SW-FAILURE
    - New event SAMA19
- Created new OR gate SAMA19-G2 with the following inputs:
    - SAMA19-G1
    - ADS
- Added gate SAMA19-G1 to the following gates:
    - LPCI-LPCS

  - BOC-003P
  - ILOC-009P
  - CTFAIL-MU-LPI
  - VENT-MU-LPI
  - RX2HRDFLR-ALTINJ (HARDWARE FAILURE OF ALTERNATE INJECTION SYSTEMS)
  - RX10RDFLR-ALTINJ (HARDWARE FAILURE OF ALTERNATE INJECTION SYSTEMS)
  - RX12RDFLR-ALTINJ (HARDWARE FAILURE OF ALTERNATE INJECTION SYSTEMS)
  - RX13RDFLR-ALTINJ (HARDWARE FAILURE OF ALTERNATE INJECTION SYSTEMS)
  - FC-HRDFLR-EXTSRC (HARDWARE FAILURE OF EXTERNAL SOURCES)
  - FC-HRDFLR-EXTSRC-SBO (HARDWARE FAILURE OF EXTERNAL SOURCES)
- Added gate SAMA19-G2 to the following gates:
  - ILOC-002P
  - ILOC-008P
  - MU-INJ (While SAMA 19 would not be impacted by harsh environmental conditions, the model structure under gate MU2 where MU-INJ is used will fail the SAMA, but it is a small contributor and is neglected for simplicity.)

The recovery tree was merged with the updated fault tree logic in order to ensure the recovery logic includes the changes from the SAMA modifications.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	**Dose-Risk**	**OECR**
Base Value	2.58E-06	7.11	$53,358
SAMA Value	1.59E-06	3.00	$22,465
Percent Change	38.4%	57.8%	57.9%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.49E-09	1.34E+00	1.37E-01	$7,222	$737
H/E	5.93E-08	4.90E-08	3.14E-01	2.59E-01	$2,763	$2,283
H/I	1.90E-08	1.72E-08	1.08E-01	9.74E-02	$954	$863
M/E	2.14E-07	1.32E-07	1.58E+00	9.75E-01	$9,395	$5,795
M/I	9.27E-07	3.55E-07	3.58E+00	1.37E+00	$32,723	$12,532
L/E	3.88E-07	3.64E-07	8.57E-02	8.04E-02	$124	$116
L/I	1.45E-07	1.13E-07	1.03E-01	8.01E-02	$177	$138
INTACT	7.45E-07	5.51E-07	1.62E-03	1.20E-03	$1	$0
Total	2.58E-06	1.59E-06	7.11E+00	3.00E+00	$53,358	$22,465

Applying the process described in Section F.4 yields an internal events cost-risk of $471,758. After accounting for "round up" of the base internal events cost-risk, this value is $472,575. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$472,575 * 5.2 = \$2,457,390$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 19 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
LSCS Unit 2	$5,657,600	$2,457,390	$3,200,210

Based on a $2,900,000 cost of implementation for LSCS, the net value for this SAMA is $300,210 ($3,200,210 - $2,900,000), which indicates this SAMA is potentially cost-beneficial.

F.6.18 SAMA 20 IMPROVE VACUUM BREAKER RELIABILITY BY INSTALLING REDUNDANT VALVES IN EACH LINE

For cases in which the vacuum breaker fails to reclose, the vapor suppression capability of the suppression pool is bypassed because an open pathway exists between the wetwell and the drywell. Events that result in a release of reactor inventory into the drywell can rapidly overpressurize containment without the condensing capability of the wetwell and cause a containment breach. Installation of redundant vacuum breakers would reduce the probability of failures that lead to suppression pool bypass.

Assumptions:

It is assumed that implementation of this SAMA will eliminate all failures of the vacuum breakers to reclose.

PRA Model Changes to Model SAMA:

The installation of the redundant vacuum breakers is modeled by setting the probability of the vacuum breakers failing to reclose to 0.0.

It is assumed that there are no negative consequences associated with installing the redundant vacuum breakers (i.e., the failure to open probability of the vacuum breakers is not increased).

Model Change(s):

The following changes were made in the cutsets:

- 2VSVBPC001A--K-- (VACUUM BREAKER 2PC001A FAILS TO RECLOSE DURING ACCIDENT RESPONSE): Probability set to 0.0.
- 2VSVBPC001B--K-- (VACUUM BREAKER 2PC001B FAILS TO RECLOSE DURING ACCIDENT RESPONSE): Probability set to 0.0.
- 2VSVBPC001C--K-- (VACUUM BREAKER 2PC001C FAILS TO RECLOSE DURING ACCIDENT RESPONSE): Probability set to 0.0.
- 2VSVBPC001D--K-- (VACUUM BREAKER 2PC001D FAILS TO RECLOSE DURING ACCIDENT RESPONSE): Probability set to 0.0.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	**Dose-Risk**	**OECR**
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.55E-06	6.98	$52,232
Percent Change	1.2%	1.8%	2.1%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	Freq.$_{BASE}$	Freq.$_{SAMA}$	Dose-Risk$_{BASE}$	Dose-Risk$_{SAMA}$	OECR$_{BASE}$	OECR$_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,223
H/E	5.93E-08	3.51E-08	3.14E-01	1.86E-01	$2,763	$1,636
H/I	1.90E-08	1.90E-08	1.08E-01	1.08E-01	$954	$954
M/E	2.14E-07	2.14E-07	1.58E+00	1.58E+00	$9,395	$9,395
M/I	9.27E-07	9.27E-07	3.58E+00	3.58E+00	$32,723	$32,723
L/E	3.88E-07	3.89E-07	8.57E-02	8.60E-02	$124	$124
L/I	1.45E-07	1.45E-07	1.03E-01	1.03E-01	$177	$177
INTACT	7.45E-07	7.38E-07	1.62E-03	1.60E-03	$1	$1
Total	2.58E-06	2.55E-06	7.11E+00	6.98E+00	$53,358	$52,232

Applying the process described in Section F.4 yields an internal events cost-risk of $1,065,514. After accounting for "round up" of the base internal events cost-risk, this value is $1,066,331. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$1,066,331 * 5.2 = \$5,544,921$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 20 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
LSCS Unit 2	$5,657,600	$5,544,921	$112,679

Based on a $1,150,000 cost of implementation for LSCS, the net value for this SAMA is -$1,037,321 ($112,679 - $1,150,000), which indicates this SAMA is not cost-beneficial.

F.6.19 SAMA 21 AUTOMATIC ATWS LEVEL CONTROL SYSTEM

For failure to scram conditions, early reduction in RPV level is important to limit the heat load sent to the containment, the reliability of which could be improved by automating the reduction of RPV level to just above -129 inches, ADS inhibit, and the "terminate and prevent" step (to disallow automatic RPV makeup from non-Feedwater sources). The logic would be required to actuate without operator interface and only actuate when the Feedwater system is available and providing makeup to the RPV. This would increase the time available for the operators to perform the other actions required early in ATWS scenarios, such as MSIV low level isolation logic bypass and SBLC initiation.

Assumptions:

This SAMA is assumed to eliminate level control failures, both early and late.

PRA Model Changes to Model SAMA:

The SAMA is modeled by setting the early and late level control actions to 0.0 in the fault tree.

Model Change(s):

The following changes were made in the fault tree:

- 2SLOP-LVLCTRLH-- (HEP: OPERATOR FAILS TO LOWER LEVEL EARLY (ATWS)): Event failure probability set to 0.0.
- 2SLOP-LATELVLH-- (HEP: OPERATOR FAILS TO CONTROL LEVEL LATE IN ATWS (COND PROB)): Event failure probability set to 0.0.
- 2ADOP-INHIB-EH-- (HEP: OPERATOR FAILS TO INHIBIT ADS WITH FEEDWATER AND EARLY LEVEL CONTROL): Event failure probability set to 0.0.
- 2ADOP-INHIBHPH-- (HEP: OPERATOR FAILS TO INHIBIT ADS - ATWS (FW AND MAIN CONDENSER AVAILABLE)): Event failure probability set to 0.0.
- 2ADOPINHIBIT-H-- (HEP: OPERATOR FAILS TO INHIBIT ADS IN ATWS (NO HP INJECTION)): Event failure probability set to 0.0.
- 2ADOP-INHIB-LH-- (HEP: OPERATOR FAILS TO INHIBIT ADS WITH FEEDWATER AND LATE LEVEL CONTROL): Event failure probability set to 0.0.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	**Dose-Risk**	**OECR**
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.22E-06	6.10	$47,165
Percent Change	14.0%	14.2%	11.6%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,223
H/E	5.93E-08	4.74E-08	3.14E-01	2.51E-01	$2,763	$2,209
H/I	1.90E-08	1.90E-08	1.08E-01	1.08E-01	$954	$954
M/E	2.14E-07	9.90E-08	1.58E+00	7.32E-01	$9,395	$4,346
M/I	9.27E-07	9.12E-07	3.58E+00	3.52E+00	$32,723	$32,194
L/E	3.88E-07	1.95E-07	8.57E-02	4.31E-02	$124	$62
L/I	1.45E-07	1.45E-07	1.03E-01	1.03E-01	$177	$177
INTACT	7.45E-07	7.19E-07	1.62E-03	1.56E-03	$1	$1
Total	2.58E-06	2.22E-06	7.11E+00	6.10E+00	$53,358	$47,165

Applying the process described in Section F.4 yields an internal events cost-risk of $953,778. After accounting for "round up" of the base internal events cost-risk, this value is $954,595. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$954{,}595 * 5.2 = \$4{,}963{,}894$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 21 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
LSCS Unit 2	$5,657,600	$4,963,894	$693,706

Based on a $1,481,002 cost of implementation for LSCS, the net value for this SAMA is -$787,296 ($693,706 - $1,481,002), which indicates this SAMA is not cost-beneficial.

F.6.20 SAMA 22 HYDROGEN IGNITORS IN PRIMARY CONTAINMENT

For cases in which containment venting is not adequate to prevent the buildup of combustible gases or when venting has failed, burning the combustible gases before they reach levels where detonation can cause containment failure is a means of reducing the consequences of severe accidents. Providing a means of power during SBO events would improve the capabilities of this system.

Assumptions:

This SAMA is assumed to eliminate combustible gas detonations.

PRA Model Changes to Model SAMA:

The SAMA is modeled by setting the failure probability of hydrogen detonation to 0.0 in the cutsets.

Model Change(s):

The following changes were made in the cutsets:

- 2CZPH-H2-DEFGF-- (HYDROGEN DEFLAGRATION OCCURS GLOBALLY): Event failure probability set to 0.0.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	**Dose-Risk**	**OECR**
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.58E-06	7.07	$53,011
Percent Change	0.0%	0.6%	0.7%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,223
H/E	5.93E-08	5.44E-08	3.14E-01	2.88E-01	$2,763	$2,535
H/I	1.90E-08	1.66E-08	1.08E-01	9.40E-02	$954	$833
M/E	2.14E-07	2.14E-07	1.58E+00	1.58E+00	$9,395	$9,395
M/I	9.27E-07	9.27E-07	3.58E+00	3.58E+00	$32,723	$32,723
L/E	3.88E-07	3.89E-07	8.57E-02	8.60E-02	$124	$124
L/I	1.45E-07	1.45E-07	1.03E-01	1.03E-01	$177	$177
INTACT	7.45E-07	7.51E-07	1.62E-03	1.63E-03	$1	$1
Total	2.58E-06	2.58E-06	7.11E+00	7.07E+00	$53,358	$53,011

Applying the process described in Section F.4 yields an internal events cost-risk of $1,080,761. After accounting for "round up" of the base internal events cost-risk, this value is $1,081,578. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{\text{SAMA}} = \$1{,}081{,}578 * 5.2 = \$5{,}624{,}206$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 22 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
LSCS Unit 2	$5,657,600	$5,624,206	$33,394

Based on a $205,000 cost of implementation for LSCS, the net value for this SAMA is -$171,606 ($33,394 - $205,000), which indicates this SAMA is not cost-beneficial.

F.6.21 SAMA 23 ENHANCE FUEL POOL EMERGENCY MAKEUP PUMP AND CONNECTION

For post core damage conditions, a system capable of injecting 1000 gpm or more to the RPV is estimated to be required to prevent reactor vessel meltthrough and core-concrete interactions that can fail the drywell. Replacing the existing Fuel Pool Emergency Makeup Pump with a higher pressure/higher flow pump and creating a permanent connection to the B RHR line could provide this capability. The capability would be similar to that of the local, manual RHRSW/LPCS cross-tie, but it makes use of a diverse system that is not currently considered in the PRA. This SAMA would also potentially be able to prevent core damage in many of the scenarios requiring water to prevent the RPV meltthrough and drywell failure events.

Assumptions:

The hard pipe connection provides a simplified means of aligning injection such that the fuel pool emergency makeup pump can be aligned in time to mitigate loss of all injection scenarios.

No credit is taken for this injection source for scenarios involving loss of inventory from the RPV via LOCAs, IORV events, or leakage after water hammer events. Credit is taken for mitigating isolated interfacing systems LOCAs because the makeup flow rate is low and there is assumed to be adequate time to respond. Credit is taken for these scenarios in post core damage periods because the requirements are different.

The local alignment requirement is assumed to preclude credit for ATWS scenarios.

The upgraded pump is assumed to be backed by the same Division 2 480V AC bus as the existing B pump (bus 236Y).

<u>PRA Model Changes to Model SAMA:</u>

The inclusion of the fuel pool emergency makeup pump cross-tie required changes to be made to both the main fault tree and the recovery fault tree. The cross-tie was assumed to require the RHR B injection path (existing logic from the LPCI system). The logic was added to the existing fault tree structure in scenarios where venting or containment failure resulted in the loss of injection systems.

<u>Model Change(s):</u>

The following change was made to the main fault tree:

- Created new basic event SAMA23 (FAILURE OF ALIGNEMNT, OPERATION, OR HARDWARE FOR EFPMU): Probability set to 1.0E-03.
- Created new OR gate SAMA23-G1 including the following inputs:
  - Gate RHRB-INJ-PATH (RHR TRAIN B INJ PATH FAULTS)
  - Gate IE-SLOCA (SMALL LOCA INITIATING EVENT)
  - Gate LOCA-NOT-S2 (LOCA INITIATORS GREATER THAN SLOCA)
  - Gate 2AP22E-PWR (LOSS OF POWER AT 480 VAC SWGR 236Y)
  - Gate SCRAM-FAILS.
  - New event SAMA23
  - Initiating event %TI (INADVERTENTLY OPEN RELIEF VALVE INITIATING EVENT)
  - Basic event 2RHSYLEAKA---L-- (RH TRAIN A FAILS DUE TO EXCESSIVE LEAKAGE FOLLOWING WATER HAMMER)
  - Basic event 2RHSYARUPTFLOOD- (RH TRAIN A WATER HAMMER INDUCED RUPTURE CAUSES FLOODING)
  - Basic event 2RHSYLEAKB---L-- (RH TRAIN B FAILS DUE TO EXCESSIVE LEAKAGE FOLLOWING WATER HAMMER)
  - Basic event 2RHSYRUPTUREBR-- (RH TRAIN B FAILS DUE TO RUPTURE FOLLOWING WATER HAMMER)
- Created new OR gate SAMA23-G2 with the following inputs:

  - ADS
  - SAMA23-G1
- Added gate SAMA23-G1 to the following gates:
  - LPCI-LPCS
  - CTFAIL-MU-LPI
  - VENT-MU-LPI
- Added new gate SAMA23-G2 to the following gates:
  - ILOC-008P
  - MU-INJ (While SAMA 23 would not be impacted by harsh environmental conditions, the model structure under gate MU2 where MU-INJ is used will fail the SAMA, but it is a small contributor and is neglected for simplicity.)
- Created new OR gate SAMA23-G1-L2 with the following inputs (to allow post core damage credit for LOCA and ATWS cases in which the injection lines would be intact):
  - Gate RHRB-INJ-PATH (RHR TRAIN B INJ PATH FAULTS)
  - Gate 2AP22E-PWR (LOSS OF POWER AT 480 VAC SWGR 236Y)
  - New event SAMA23
  - Basic event 2RHSYLEAKB---L-- (RH TRAIN B FAILS DUE TO EXCESSIVE LEAKAGE FOLLOWING WATER HAMMER)
  - Basic event 2RHSYRUPTUREBR-- (RH TRAIN B FAILS DUE TO RUPTURE FOLLOWING WATER HAMMER)
  - %ISLOCA-RHRB-S (RHR B SDC RETURN LINE ISLOCA)
  - %ISLOCA-RHRB (RHR B INJECTION LINE ISLOCA)
- Added new gate SAMA23-G1-L2 to the following gates
  - RX2HRDFLR-ALTINJ (HARDWARE FAILURE OF ALTERNATE INJECTION SYSTEMS)
  - RX10RDFLR-ALTINJ (HARDWARE FAILURE OF ALTERNATE INJECTION SYSTEMS)
  - RX12RDFLR-ALTINJ (HARDWARE FAILURE OF ALTERNATE INJECTION SYSTEMS)
  - RX13RDFLR-ALTINJ (HARDWARE FAILURE OF ALTERNATE INJECTION SYSTEMS)
  - FC-HRDFLR-EXTSRC (HARDWARE FAILURE OF EXTERNAL SOURCES)
  - FC-HRDFLR-EXTSRC-SBO (HARDWARE FAILURE OF EXTERNAL SOURCES)

The recovery tree was merged with the updated fault tree logic in order to ensure the recovery logic includes the changes from the SAMA modifications.

<u>Results of SAMA Quantification:</u>

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	1.89E-06	3.87	$25,797
Percent Change	26.7%	45.6%	51.7%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,223
H/E	5.93E-08	4.91E-08	3.14E-01	2.60E-01	$2,763	$2,288
H/I	1.90E-08	8.60E-09	1.08E-01	4.87E-02	$954	$432
M/E	2.14E-07	1.41E-07	1.58E+00	1.04E+00	$9,395	$6,190
M/I	9.27E-07	2.67E-07	3.58E+00	1.03E+00	$32,723	$9,425
L/E	3.88E-07	3.58E-07	8.57E-02	7.91E-02	$124	$114
L/I	1.45E-07	1.02E-07	1.03E-01	7.23E-02	$177	$124
INTACT	7.45E-07	8.81E-07	1.62E-03	1.91E-03	$1	$1
Total	2.58E-06	1.89E-06	7.11E+00	3.87E+00	$53,358	$25,797

Applying the process described in Section F.4 yields an internal events cost-risk of $556,276. After accounting for "round up" of the base internal events cost-risk, this value is $557,093. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$557,093 * 5.2 = \$2,896,884$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 23 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
LSCS Unit 2	$5,657,600	$2,896,884	$2,760,716

Based on a $1,370,000 cost of implementation for LSCS, the net value for this SAMA is $1,390,716 ($2,760,716 - $1,370,000), which indicates this SAMA is potentially cost-beneficial.

F.6.22 SAMA 24 PROVIDE INTER DIVISION 4KV AC CROSS-TIE CAPABILITY

The existing inter-unit cross-tie capability is valuable at LSCS, but additional flexibility could be gained by providing the capability to perform inter-divisional AC cross-ties in accident scenarios (e.g., 241Y to 242Y, or 242Y to 243C).

Assumptions:

Failure to perform the inter-unit cross-tie and the inter-division cross-tie are completely dependent (the same HFE is used for all cross-ties).

Any 4KV emergency bus can be supplied by any other emergency 4kV bus from the same unit.

PRA Model Changes to Model SAMA:

The implementation of the inter-division cross-tie is modeled by including the other two diesel generators from the same unit as potential power supply sources for a given emergency bus.

Model Change(s):

The following changes were made to the division 1 logic under gate 241Y-PWR-SOURCES in the fault tree:

- Under existing gate 241Y-PWR-SOURCES, added new gate SAMA24-G1.
- New gate SAMA24-G1 (X-TIE FROM OTHER DIVISIONS ON SAME UNIT): OR gate with the following inputs:
  - Existing gate 2AP04E-FLT (4KV 241Y FAULTS)
  - Existing event 2ACOP142-242-H-- (HEP: OPERATOR FAILS TO CROSS TIE 4kV BUS TO OTHER UNIT)
  - New gate SAMA24-G2 (OTHER UNIT SOURCES)
- Created new gate SAMA24-G2 (OTHER UNIT SOURCES): AND gate with the following inputs:
  - New gate SAMA24-G3 (242 POWER)
  - New gate SAMA24-G4 (243 POWER)
- Created new gate SAMA24-G3 (242 POWER): OR gate with the following 2 inputs:
  - Existing gate 2AP06E-FLT (4KV 242Y FAULTS)
  - Existing gate DG2A-FAILURE (DG2A FAILURE)

- Created new gate SAMA24-G4 (243 POWER): OR gate with the following 2 inputs)
  - Existing gate 1E243C-FAULTS (4KV BUS 243C FAULTS (2AP07E))
  - Existing gate DG2B-FAILURE (DG2B FAILURE)

The changes made to FLOOD versions of the Division 1 power logic and for the other divisions were similar. The top gates associated with the logic changes are:

- 241Y-PWRSOURCESF
- 242Y-PWR-SOURCES
- 242Y-PWRSOURCESF
- 243C-PWR-SOURCES
- 243C-PWRSOURCESF

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.46E-06	6.73	$50,036
Percent Change	4.7%	5.3%	6.2%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,223
H/E	5.93E-08	5.91E-08	3.14E-01	3.13E-01	$2,763	$2,754
H/I	1.90E-08	1.37E-08	1.08E-01	7.75E-02	$954	$688
M/E	2.14E-07	2.11E-07	1.58E+00	1.56E+00	$9,395	$9,263
M/I	9.27E-07	8.45E-07	3.58E+00	3.26E+00	$32,723	$29,829
L/E	3.88E-07	3.87E-07	8.57E-02	8.55E-02	$124	$123
L/I	1.45E-07	1.28E-07	1.03E-01	9.08E-02	$177	$156
INTACT	7.45E-07	7.33E-07	1.62E-03	1.59E-03	$1	$1
Total	2.58E-06	2.46E-06	7.11E+00	6.73E+00	$53,358	$50,036

Applying the process described in Section F.4 yields an internal events cost-risk of $1,022,497. After accounting for “round up” of the base internal events cost-risk, this value is $1,023,314. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{\text{SAMA}} = \$1{,}023{,}314 * 5.2 = \$5{,}321{,}233$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 24 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
LSCS Unit 2	$5,657,600	$5,321,233	$336,367

Based on a $1,824,084 cost of implementation for LSCS, the net value for this SAMA is -$1,487,717 ($336,367 - $1,824,084), which indicates this SAMA is not cost-beneficial.

F.6.23 SAMA 25 PERIODIC TRAINING ON WATER HAMMER SCENARIOS RESULTING FROM A FALSE LOCA SIGNAL

In transient scenarios, even with RHR operating in SPC mode, the DW will still reach 2 psig and a high DW pressure signal will register. When a consequential loss of offsite power occurs with the LOCA signal, this results in a load shed of the emergency buses while the EDGs start, during which time the discharge line of the previously running RHR train will drain to the suppression pool. When the RHR system is reloaded onto the emergency bus and the RHR pump starts, the discharge line will be empty and vulnerable to a water hammer event (PRA specific scenario). Incorporating training on this scenario into the Licensed Operator Cycle Training Plans would institutionalize it in a manner that would help ensure the operators maintain proficiency in addressing these types of scenarios and potentially improve the reliability of the actions required to prevent a water hammer event.

<u>Assumptions:</u>

It is assumed that the implementation of this SAMA would make the action to vent the drywell to prevent the 2 psig signal from registering (2CVOP2INCHVNTH--) highly familiar to the operators. The improvement in the training can be reflected in the PRA by the use of the lower bound ASEP curve in place of the median curve. The change in training would not impact the timing, the PSFs, or the recovery dependencies used in the action assessment such that the updated HEP would be calculated by removing the current ASEP contribution of 6.9E-02 and replacing it with 2.6E-03. This change results in a reduction of the HEP from 9.1E-02 to 2.5E-02.

The JHEPs including the action 2CVOP2INCHVNTH-- are reduced by the ratio of the new HEP to the old HEP (2.5E-02 / 9.1E-02 = 0.27).

PRA Model Changes to Model SAMA:

This SAMA was modeled by changing basic event values in the cutsets to reflect the improved reliability of the drywell venting action for preventing a LOCA signal in non-LOCA cases.

Model Change(s):

The following event probability changes were made to the cutsets:

- 2CVOP2INCHVNTH-- (HEP: OPERATOR FAILS TO OPEN 2" LINES TO MAINTAIN DW PRESSURE BELOW HI DW SETPOINT): HEP changed to 2.5E-02.
- 2RX-CVRHACFP5H-- (JHEP): Set to 3.8E-06.
- 2RX-CV-RH-AC4H-- (JHEP): Set to 7.6E-06.
- 2RX-WHLTRIPL3H-- (JHEP): Set to 1.3E-03.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	Dose-Risk	OECR
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.44E-06	6.92	$52,887
Percent Change	5.4%	2.7%	0.9%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,223
H/E	5.93E-08	5.82E-08	3.14E-01	3.08E-01	$2,763	$2,712
H/I	1.90E-08	1.90E-08	1.08E-01	1.08E-01	$954	$954

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
M/E	2.14E-07	2.13E-07	1.58E+00	1.57E+00	$9,395	$9,351
M/I	9.27E-07	9.24E-07	3.58E+00	3.57E+00	$32,723	$32,617
L/E	3.88E-07	3.86E-07	8.57E-02	8.53E-03	$124	$12
L/I	1.45E-07	1.43E-07	1.03E-01	1.01E-02	$177	$17
INTACT	7.45E-07	6.14E-07	1.62E-03	1.33E-03	$1	$1
Total	2.58E-06	2.44E-06	7.11E+00	6.92E+00	$53,358	$52,887

Applying the process described in Section F.4 yields an internal events cost-risk of $1,070,541. After accounting for "round up" of the base internal events cost-risk, this value is $1,071,358. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$1,071,358 * 5.2 = \$5,571,062$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 25 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
LSCS Unit 2	$5,657,600	$5,571,062	$86,538

Based on a $112,000 cost of implementation for LSCS, the net value for this SAMA is -$25,462 ($86,538 - $112,000), which indicates this SAMA is not cost-beneficial.

F.6.24 SAMA 27 PRECLUDE EMERGENCY DEPRESSURIZATION WHEN RCIC IS THE ONLY INJECTION SYSTEM AVAILABLE AND PROVIDE LONG TERM DC POWER

For cases where RCIC is the only injection system available, it would be possible to prevent core damage by changing the EOPs to allow RPV pressure to be maintained in the range of 150 to 250 psig even when containment temperature and pressure limits are violated. This would ensure the RCIC steam head is not lost in long term loss of containment heat removal scenarios. Providing a 480V AC generator to supply a battery charger would maintain plant instrumentation and control power, which would improve the reliability of this strategy.

In addition to these changes, it is likely that some additional modifications would be required to maintain RCIC operation in long term SBO cases, such as changing procedures to bypass the

RCIC high containment back pressure turbine trip logic. These changes are assumed to be included as part of this SAMA, but are not added to the cost of implementation.

Assumptions:

This SAMA eliminates the risk associated with scenarios in which RCIC is initially operational in SBO scenarios.

It is assumed that an SORV initiator does not depressurize the RPV to the point where RCIC is unavailable. This conservatively increases the benefit of the SAMA.

Any additional changes required to ensure RCIC is operational in long term SBO scenarios are assumed to be included as part of this SAMA, such as procedure changes to bypass the RCIC high containment back pressure turbine trip logic.

PRA Model Changes to Model SAMA:

The SAMA is modeled by setting the failure probability of sequences in which RCIC is initially operation in an SBO to 0.0 in the cutsets.

Model Change(s):

The following sequence flags were set to 0.0 in the cutsets:

- RCVSEQ-DLOP-025, RCVSEQ-DLOP-028, RCVSEQ-DLOP-030, RCVSEQ-DLOP-032, RCVSEQ-LOOP-025, RCVSEQ-LOOP-028, RCVSEQ-LOOP-030, RCVSEQ-LOOP-032, RCVSEQ-SRVD-028, RCVSEQ-SRVD-031, RCVSEQ-SRVD-035, RCVSEQ-SRVD-038, RCVSEQ-SRVD-040, RCVSEQ-SRVL-028, RCVSEQ-SRVL-031, RCVSEQ-SRVL-035, RCVSEQ-SRVL-038, RCVSEQ-SRVL-040, RCVSEQ-TBFLD-008, RCVSEQ-TBFLD-010, RCVSEQ-TBFLD-013, RCVSEQ-TBFLD-015, RCVSEQ-TBFLD-016, RCVSEQ-TBFLD-017.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	**Dose-Risk**	**OECR**
Base Value	2.58E-06	7.11	$53,358
SAMA Value	2.47E-06	6.90	$51,607
Percent Change	4.3%	3.0%	3.3%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,223
H/E	5.93E-08	5.92E-08	3.14E-01	3.13E-01	$2,763	$2,759
H/I	1.90E-08	4.60E-09	1.08E-01	2.60E-02	$954	$231
M/E	2.14E-07	2.14E-07	1.58E+00	1.58E+00	$9,395	$9,395
M/I	9.27E-07	8.99E-07	3.58E+00	3.47E+00	$32,723	$31,735
L/E	3.88E-07	3.89E-07	8.57E-02	8.60E-02	$124	$124
L/I	1.45E-07	1.15E-07	1.03E-01	8.15E-02	$177	$140
INTACT	7.45E-07	7.06E-07	1.62E-03	1.53E-03	$1	$1
Total	2.58E-06	2.47E-06	7.11E+00	6.90E+00	$53,358	$51,607

Applying the process described in Section F.4 yields an internal events cost-risk of $1,051,512. After accounting for “round up” of the base internal events cost-risk, this value is $1,052,329. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$1,052,329 * 5.2 = \$5,472,111$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 27 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
LSCS Unit 2	$5,657,600	$5,472,111	$185,489

Based on a $512,000 cost of implementation for LSCS, the net value for this SAMA is -$326,511 ($185,489 - $512,000), which indicates this SAMA is not cost-beneficial.

F.7 SENSITIVITY ANALYSIS

NEI 05-01 recommends that applicants perform sensitivity analyses that evaluate how changes to certain assumptions and uncertainties in the SAMA analysis would affect the cost-benefit analysis outcome. Accordingly, the following uncertainties were further investigated as to their impact on the overall SAMA evaluation:

- Use of a discount rate of 7 percent, instead of 3 percent used in the base case analysis.

- Use of the 95th percentile PRA results in place of the point estimate PRA results.
- Variations in selected MACCS2 input variables.
- Inclusion of the reliable hard pipe vent on potentially cost-beneficial SAMAs

F.7.1 REAL DISCOUNT RATE

The RDR is an estimate of the the rate of return on invested dollars above the rate of inflation. A scenario with a low RDR would require a larger investment of present day dollars to pay for a future expense than a scenario with a relativley high RDR. In a SAMA analysis, large RDRs reduce the averted cost-risk values associated with SAMA implementation relative to low RDRs because the present day dollar investment to pay for accident mitigation would be less.

The baseline SAMA analysis uses an RDR of 3 percent, which could be viewed as conservative given that NUREG/BR-0184 suggests the use of an RDR of 7 percent (NRC 1997). In this sensitivity case, the Phase 1 and Phase 2 results were re-evaluated using the 7 percent RDR suggested in NUREG/BR-0184.

For the Phase 1 analysis, the MACR was recalculated using the methodology outlined in Section F.4, and the SAMA implementation costs were compared to the revised MACR. Based on the reduction of the MACR to $4,087,200 (a 28 percent reduction of the baseline MACR), SAMA 12 would be screened in the Phase 1 analysis due to the use of the 7 percent RDR.

For the Phase 2 analysis, the determination of cost effectiveness changed for one of the Phase 2 SAMAs when the 7 percent RDR was used in lieu of 3 percent, as shown below.

Summary of the Impact of the RDR Value on the Detailed SAMA Analyses

SAMA ID	Implementation Cost (per unit)	Averted Cost Risk (3 percent RDR)	Net Value (3 percent RDR)	Averted Cost Risk (7 percent RDR)	Net Value (7 percent RDR)	Change in Cost Effective-ness?
SAMA 1	$12,940,000	$2,294,729	-$10,645,271	$1,652,654	-$11,287,346	No
SAMA 2	$400,000	$1,305,668	$905,668	$939,687	$539,687	No
SAMA 3	$1,000,000	$935,157	-$64,843	$672,479	-$327,521	No
SAMA 4	$635,242	$622,258	-$12,984	$451,500	-$183,742	No
SAMA 5	$400,000	$355,690	-$44,310	$257,488	-$142,512	No

Summary of the Impact of the RDR Value on the Detailed SAMA Analyses

SAMA ID	Implementation Cost (per unit)	Averted Cost Risk (3 percent RDR)	Net Value (3 percent RDR)	Averted Cost Risk (7 percent RDR)	Net Value (7 percent RDR)	Change in Cost Effective-ness?
SAMA 6	$2,900,000	$79,362	-$2,820,638	$57,231	-$2,842,769	No
SAMA 7	$962,403	$49,488	-$912,915	$38,215	-$924,188	No
SAMA 8	$400,000	$242,190	-$157,810	$174,938	-$225,062	No
SAMA 9	$115,000	$207,865	$92,865	$152,136	$37,136	No
SAMA 10	$260,219	$1,208,038	$947,819	$867,901	$607,682	No
SAMA 11	$217,415	$19,703	-$197,712	$14,695	-$202,720	No
SAMA 14	$489,277	$414,170	-$75,107	$299,780	-$189,497	No
SAMA 15	$1,370,000	$3,154,871	$1,784,871	$2,271,885	$901,885	No
SAMA 16	$475,000	$793,161	$318,161	$572,780	$97,780	No
SAMA 18	$649,194	$560,082	-$89,112	$404,050	-$245,144	No
SAMA 19	$2,900,000	$3,200,210	$300,210	$2,304,775	-$595,225	Yes
SAMA 20	$1,150,000	$112,679	-$1,037,321	$81,073	-$1,068,927	No
SAMA 21	$1,481,002	$693,706	-$787,296	$501,748	-$979,254	No
SAMA 22	$205,000	$33,394	-$171,606	$23,899	-$181,101	No
SAMA 23	$1,370,000	$2,760,716	$1,390,716	$1,985,838	$615,838	No
SAMA 24	$1,824,084	$336,367	-$1,487,717	$242,481	-$1,581,603	No
SAMA 25	$112,000	$86,538	-$25,462	$63,996	-$48,004	No
SAMA 27	$512,000	$185,489	-$326,511	$134,363	-$377,637	No

F.7.2 95TH PERCENTILE PRA RESULTS

The results of the SAMA analysis can be impacted by implementing conservative values from the PRA's uncertainty distribution. If the best estimate failure probability values were consistently lower than the "actual" failure probabilities, the PRA model would underestimate plant risk and yield lower than "actual" averted cost-risk values for potential SAMAs. Re-assessing the cost-benefit calculations using the high end of the failure probability distributions is a means of identifying the impact of having consistently underestimated failure probabilities for plant equipment and operator actions included in the PRA model. This sensitivity uses the Level 1 95th percentile results to examine the impact of uncertainty in the PRA model.

In performing the sensitivity analysis, only the base case was used in determining the appropriate value for the 95th percentile. For those SAMAs that required the addition of new basic events, no new uncertainty distributions were assigned since the design and implementation of each SAMA was arbitrary and was defined by the analysis assumptions. The results of this uncertainty analysis, therefore, show the expected statistical uncertainty of the CDF risk metrics under the assumption that each SAMA was designed and implemented as it was specified in this analysis. All calculations were performed using version 3.0 of the EPRI Uncert software package for the LSCS Unit 2 model.

The results of the uncertainty calculation show that the 95th percentile CDF is 5.52E-06, which is a factor of 2.14 greater than the LSCS 2013A CDF point estimate of 2.58E-06. Therefore, for this analysis, the 95th percentile multiplier derived from the base case is used to examine the change in the cost benefit for each SAMA.

F.7.2.1 PHASE 1 IMPACT

For Phase 1 screening, use of the 95th percentile PRA results will increase the MACR and may prevent the screening of some of the higher cost modifications. However, the impact on the overall SAMA results due to the retention of the higher cost SAMAs for Phase 2 analysis is typically small. This is due to the fact that the benefit obtained from the implementation of those SAMAs must be extremely large in order to be cost-beneficial.

The impact of uncertainty in the PRA results on the Phase 1 SAMA analysis has been examined. The MACR is the primary Phase 1 criterion affected by PRA uncertainty. Thus, this portion of the sensitivity is focused on recalculating the MACR using the 95th percentile PRA results and re-performing the Phase 1 screening process. As discussed above, the 95th PRA results are a factor of 2.14 greater than the point estimate CDF.

In order to simulate the use of the 95th percentile PRA results on the cost benefit calculations, the same scaling factor calculated for the Level 1 results was assumed to apply to the Level 3 results. Because the MACR calculations scale linearly with the CDF, dose-risk, and off-site economic cost-risk, the 95th percentile MACR can be calculated by multiplying the base case MACR by 2.14. This results in a 95th percentile MACR of $12,107,264.

The initial SAMA list has been re-examined using the revised MACR to identify SAMAs that would have been retained for the Phase 2 analysis. Those SAMAs that were previously screened due to costs of implementation that exceeded $5,657,600 are now retained if the costs of implementation are less than $12,107,264. For LSCS, SAMAs 17 and 26 were screened in the Phase 1 analysis based on excessive implementation cost (SAMA 1 will be implemented regardless of cost and it was not screened). Because the SAMA 26 implementation cost is less than the 95th percentile MACR, it has been retained for Phase 2 analysis, as documented below.

F.7.2.1.1 SAMA 26: Seismically Qualified Low Pressure RPV Makeup Capability

For seismic initiators that lead to SBOs and early failure of RCIC, aligning the Fire Protection System to the Feedwater system using fire hoses cannot currently prevent core damage. In order to mitigate these types of events, a hard-piped, seismically qualified low pressure injection pump with a seismically qualified suction source and power source would be required. This would ensure the system would be available in seismic events. In order to ensure it could be rapidly aligned for loss of injection cases, this SAMA includes the ability to align the system from the MCR. For power, a non-safety related, seismically qualified diesel generator would be required to energize the pump and to provide long term battery charger support to maintain RPV level instrumentation and SRV control for low pressure injection. The generator would be permanently installed outside of the Reactor Building and would include remote start capability from the MCR to power the makeup pump. Alignment to the existing safety related battery chargers would be performed manually within 4 hours. Ensuring that this capability would likely be available for seismic events with peak ground accelerations of up to 0.46g would address most of the estimated risk.

Assumptions:

The connection provides a simplified means of aligning injection such that emergency makeup to the RPV can be aligned in time to mitigate loss of all injection scenarios.

No credit is taken for this injection source for scenarios involving loss of inventory from the RPV via LOCAs, IORV events, or leakage after water hammer events. Credit is taken for mitigating isolated interfacing systems LOCAs because the makeup flow rate is low and there is assumed to be adequate time to respond. In addition, this SAMA is credited in the un-isolated interfacing system LOCA leak because of the low makeup requirements.

No power dependencies are assumed for this injection source given that it is backed by its own diesel. The SAMA 26 diesel does supply power to the existing 480V system to support the station battery chargers, but failure of the hardware is assumed to be a small contributor to the overall failure probability and those failures are not explicitly included.

The injection line connects to the Feedwater line, but it is assumed to be tied in downstream of the flow control valves such that there are no dependencies on the Feedwater valve support systems.

Credit is not taken in ATWS events due to limited makeup capacity.

The pump is sized to provide 600 gpm to each unit simultaneously. This flow rate is less than the 1000 gpm required for several post core damage mitigation functions, including preventing RPV meltthrough, preventing drywell failure, containment flooding, and makeup after containment failure. No credit is taken for those functions.

PRA Model Changes to Model SAMA:

The inclusion of the seismically qualified makeup source required changes to be made to both the main fault tree and the recovery fault tree. The logic was added to the existing fault tree structure in scenarios where LPCI and LPCS are credited and where containment failure results in the loss of injection systems due to adverse environmental conditions. Logic was included in the fault tree preclude credit for loss of inventory scenarios where the 600 gpm makeup rate may be inadequate (e.g., LOCA events and makeup to prevent RPV meltthrough).

Model Change(s):

The following change was made to the main fault tree:

- Created new basic event SAMA26 (FAILURE OF SEISMICALLY QUALIFIED INJECTION SOURCE): Probability set to 1.0E-03.
- Created new gate SAMA26-G1: OR gate including event SAMA 26 and the following existing gates:
  - New event SAMA26
  - Gate IE-SLOCA (SMALL LOCA INITIATING EVENT)
  - Gate LOCA-NOT-S2 (LOCA INITIATORS GREATER THAN SLOCA)
  - Initiating event %TI (INADVERTENTLY OPEN RELIEF VALVE INITIATING EVENT)
  - Basic event 2RHSYLEAKA---L-- (RH TRAIN A FAILS DUE TO EXCESSIVE LEAKAGE FOLLOWING WATER HAMMER)

- Basic event 2RHSYARUPTFLOOD- (RH TRAIN A WATER HAMMER INDUCED RUPTURE CAUSES FLOODING)
- Basic event 2RHSYLEAKB---L-- (2RHSYLEAKB---L--
- Basic event 2RHSYRUPTUREBR-- (RH TRAIN B FAILS DUE TO RUPTURE FOLLOWING WATER HAMMER)
- Gate SCRAM-FAILS

- Created new gate SAMA26-G2: OR gate with the following inputs:
  - Event SAMA26
  - ADS
- Added new gate SAMA26-G1 to the following gates:
  - CTFAIL-MU-LPI
  - VENT-MU-LPI
  - LPCI-LPCS
  - LPI-TBRB-FLD
  - LPI-FSTB
- Added new OR gate SAMA26-G2 to the following gates:
  - ILOC-002P
  - ILOC-008P
- Added event SAMA26 under gate ILOC-006P.
- Under existing gate TD8-RPV:
  - Deleted gate LPCI-LPCS (precludes crediting SAMA26 for the debris cooling function)
  - Added existing gates LPCI and LPCS

The recovery tree was merged with the updated fault tree logic in order to ensure the recovery logic includes the changes from the SAMA modifications.

Results of SAMA Quantification:

The following table summarizes the changes to the internal events CDF, Dose-Risk, and Offsite Economic Cost-Risk resulting from the implementation of this SAMA:

	Internal CDF	**Dose-Risk**	**OECR**
Base Value	2.58E-06	7.11	$53,358
SAMA Value	1.85E-06	4.78	$32,652
Percent Change	28.3%	32.8%	38.8%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
H/E-BOC	8.32E-08	8.32E-08	1.34E+00	1.34E+00	$7,222	$7,223
H/E	5.93E-08	5.89E-08	3.14E-01	3.12E-01	$2,763	$2,745
H/I	1.90E-08	9.30E-09	1.08E-01	5.26E-02	$954	$467
M/E	2.14E-07	1.98E-07	1.58E+00	1.46E+00	$9,395	$8,692
M/I	9.27E-07	3.76E-07	3.58E+00	1.45E+00	$32,723	$13,273
L/E	3.88E-07	3.65E-07	8.57E-02	8.07E-02	$124	$116
L/I	1.45E-07	1.11E-07	1.03E-01	7.87E-02	$177	$135
INTACT	7.45E-07	6.49E-07	1.62E-03	1.41E-03	$1	$1
Total	2.58E-06	1.85E-06	7.11E+00	4.78E+00	$53,358	$32,652

Applying the process described in Section F.4 yields an internal events cost-risk of $685,646. After accounting for "round up" of the base internal events cost-risk, this value is $686,463. The external events contributions are accounted for by multiplying this value by 5.2:

$$\text{Total Cost-Risk}_{SAMA} = \$686{,}463 * 5.2 = \$3{,}569{,}608$$

This information was used as input to the averted cost-risk calculation. The results of this calculation are provided in the following table:

SAMA 26 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
LSCS Unit 2	$5,657,600	$3,569,608	$2,087,992

Based on a $5,984,407 cost of implementation for LSCS, the net value for this SAMA is -$3,896,415 ($2,087,992 - $5,984,407). When the 95th percentile PRA results are used, the averted cost-risk is increased by a factor of 2.14 to $4,468,303, which still yields a negative net value ($4,468,303 - $5,984,407 = -$1,516,104). This SAMA is not cost-beneficial.

F.7.2.2 PHASE 2 IMPACT

As discussed above, a single factor based on the 95th percentile for the base case is used to determine the impact of the cost-benefit analysis for the proposed SAMA candidates. The uncertainty analyses that are available for the Level 1 model are not available (or not used) for the Level 2 and 3 PRA models. In order to simulate the use of the 95th percentile results for the Level 2 and 3 models, the same scaling factor calculated for the Level 1 results was implicitly applied to the dose-risk and offsite economic cost-risk through the application of the multiplier to the base case averted cost-risk values.

The Phase 2 SAMA list was re-examined by multiplying the nominal averted cost-risk by the ratio of the 95th percentile CDF to the point estimate CDF value (see Section 7.2) to identify SAMAs that would be re-characterized as potentially cost-beneficial, i.e., positive net value. Those SAMAs that were previously determined to be not cost-beneficial due to implementation costs exceeding their associated nominal averted cost risk may be potentially cost-beneficial at the revised 95th percentile averted cost risk. In this case, eight additional Phase 2 SAMAs become potentially cost-beneficial (SAMAs 3, 4, 5, 8, 14, 18, 21, and 25).

F.7.2.3 95TH PERCENTILE SUMMARY

The following table provides a summary of the impact of using the 95th percentile PRA results on the detailed cost-benefit calculations that have been performed.

Summary of the Impact of Using the 95th Percentile PRA Results

SAMA ID	Implementation Cost (per unit)	Averted Cost Risk (Base)	Net Value (Base)	Averted Cost Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effectiveness?
SAMA 1	$12,940,000	$2,294,729	-$10,645,271	$4,910,720	-$8,029,280	No
SAMA 2	$400,000	$1,305,668	$905,668	$2,794,130	$2,394,130	No
SAMA 3	$1,000,000	$935,157	-$64,843	$2,001,236	$1,001,236	Yes
SAMA 4	$635,242	$622,258	-$12,984	$1,331,632	$696,390	Yes
SAMA 5	$400,000	$355,690	-$44,310	$761,177	$361,177	Yes
SAMA 6	$2,900,000	$79,362	-$2,820,638	$169,835	-$2,730,165	No
SAMA 7	$962,403	$49,488	-$912,915	$105,904	-$856,499	No
SAMA 8	$400,000	$242,190	-$157,810	$518,287	$118,287	Yes
SAMA 9	$115,000	$207,865	$92,865	$444,831	$329,831	No
SAMA 10	$260,219	$1,208,038	$947,819	$2,585,201	$2,324,982	No
SAMA 11	$217,415	$19,703	-$197,712	$42,164	-$175,251	No
SAMA 12	$4,401,674	$986,929	-$3,414,745	$2,112,028	-$2,289,646	No
SAMA 14	$489,277	$414,170	-$75,107	$886,324	$397,047	Yes
SAMA 15	$1,370,000	$3,154,871	$1,784,871	$6,751,424	$5,381,424	No
SAMA 16	$475,000	$793,161	$318,161	$1,697,365	$1,222,365	No
SAMA 18	$649,194	$560,082	-$89,112	$1,198,575	$549,381	Yes
SAMA 19	$2,900,000	$3,200,210	$300,210	$6,848,449	$3,948,449	No
SAMA 20	$1,150,000	$112,679	-$1,037,321	$241,133	-$908,867	No
SAMA 21	$1,481,002	$693,706	-$787,296	$1,484,531	$3,529	Yes
SAMA 22	$205,000	$33,394	-$171,606	$71,463	-$133,537	No
SAMA 23	$1,370,000	$2,760,716	$1,390,716	$5,907,932	$4,537,932	No
SAMA 24	$1,824,084	$336,367	-$1,487,717	$719,825	-$1,104,259	No
SAMA 25	$112,000	$86,538	-$25,462	$185,191	$73,191	Yes
SAMA 26	$5,984,407	$2,087,992	-$3,896,415	$4,468,303	-$1,516,104	No
SAMA 27	$512,000	$185,489	-$326,511	$396,946	-$115,054	No

When the 95th percentile PRA results were applied to the Phase 1 analysis, the increase in the MACR resulted in the retention of only one SAMAs that was screened in the baseline Phase 1 analysis (SAMA 26). The Phase 2 analysis performed for SAMA 26 using the 95th percentile PRA results confirmed that SAMA 26 is not cost-beneficial.

When the 95th percentile PRA results were applied to the Phase 2 analysis, eight SAMAs (3, 4, 5, 8, 14, 18, 21, and 25) that were previously classified as not cost-effective were determined to be potentially cost-effective. The use of the 95th percentile PRA results is not considered to provide the best assessment of the cost-effectiveness of a SAMA. Instead, it is intended to address the uncertainties inherent in the SAMA analysis. Nonetheless, these additional SAMAs identified as potentially cost-benefical through this sensitivity case (none of which is related to aging management under 10 C.F.R. Part 54) should be further evaluated for possible implementation using current, applicable plant procedures.

F.7.3 MACCS2 INPUT VARIATIONS

The MACCS2 model was developed using the best information available for the LSCS site; however, reasonable changes to modeling assumptions can lead to variations in the Level 3 PRA results. In order to determine how certain assumptions could impact the SAMA results, a sensitivity analysis was performed on parameters that have previously been shown to impact the Level 3 results. These parameters include:

- Meteorological data
- Evacuation timing and speed
- Release height and heat
- Deposition velocity
- Population estimates
- Population resettlement planning
- Generic economic inputs
- Economic rate of return
- Value of farm and non-farm wealth

The risk metrics produced by MACCS2 that are evaluated in the sensitivity analyses are the 50-mile population dose risk and the 50 mile offsite economic cost risk. The subsections below discuss the changes in these results for each of the sensitivity parameters noted above. The final subsection, F.7.3.9, correlates the worst case changes identified in the sensitivity runs to a change in the site's averted cost-risk and discusses the implications of the sensitivity analysis on the SAMA analysis. The results of the individual sensitivity cases are summarized in the following table.

Sensitivity of LSCS Baseline Risk to Parameter Changes

Parameter	Description	Pop. Dose Risk Δ Base (%)	Cost Risk Δ Base (%)
Meteorology	Year 2010 Meteorology	-4%	-9%
	Year 2011 Meteorology	-1%	-6%
Evacuation Time	Evacuation delay time increased from 100 minutes to 200 minutes (factor of 2)	+1%	0%
Evacuation Speed	Average evacuation speed decreased by half from 1.6 m/sec to 0.8 m/sec.	+5%	0%
Release Height	Release height set to ground level (in lieu of mid-height of Reactor Building, 28.0 m).	-2%	-2%
	Release height set to top of Reactor Building, 56.1 m (in lieu of mid-height of containment, 28.0 m).	+2%	+3%
Release Heat	No buoyant plume assumed (0 watts for each plume segment).	+0.1%	-2%
Deposition Velocity	Dry deposition velocity decreased from 0.01 m/sec to 0.003 m/sec	-1%	-31%
Population	Year 2043 population uniformly increased 30%	+29%	+29%
Resettlement Planning	No “Intermediate Phase” resettlement planning (in lieu of 6 months)	+12%	-40%
	1 year “Intermediate Phase” resettlement planning (in lieu of 6 months)	-10%	+40%
Economic Inputs	Generic economic inputs increased (factor of 2)	-3%	+54%
Rate of Return	3% expected rate of return (in lieu of 7%)	+0.7%	-9%
	12% expected rate of return (in lieu of 7%)	-0.3%	+11%
Value of Farm and Non-Farm Wealth	Doubled value of farm wealth (11,937 $/hectare) and non-farm wealth (283,637 $/person) to 23,874 $/hectare and 567,274 $/person, respectively.	+0.4%	+59%

F.7.3.1 METEOROLOGICAL SENSITIVITIES

In addition to the year 2012 base case meteorological data, years 2010 and 2011 were also analyzed. Analysis of year 2010 and 2011 data sets yielded population dose-risks and cost risks that were 1% to 9% less than 2012 results. As no particular criteria have been defined by the industry related to determining which meteorological data set should be used as a base case for a site, the year 2012 data is chosen for LSCS because it represents site meteorological conditions and results in the highest estimated dose risk and cost risk of the three data sets.

F.7.3.2 EVACUATION SENSITIVITIES

The sensitivity of two evacuation parameters was assessed. The delay time to evacuation (increased from 100 minutes to 200 minutes) was found to have a minor impact (approximately 1% increase) on population dose risk. The evacuation speed sensitivity which decreased the average radial evacuation speed by a factor of two (from 1.6 m/sec to 0.8 m/sec) demonstrates a small impact on population dose. The population dose risk increased approximately 5% using the slower evacuation speed. An increase in population dose is the generally expected result for a delayed evacuation or a slower evacuation speed since evacuees would be expected to be exposed to releases for a longer period of time. It is noted that while evacuation assumptions do impact the population dose-risk estimates, they do not impact MACCS2 offsite economic cost-risk estimates because MACCS2-calculated cost-risks are based on land contamination levels which remain unaffected by evacuation assumptions and the number of people evacuating.

F.7.3.3 RELEASE HEIGHT & HEAT SENSITIVITIES

The release height sensitivity cases quantify the impact of the assumption related to the height of the release of the plumes. The baseline case assumes that the releases occur at approximately half the height of the containment building (28.0 m). Releases from higher heights tend to disperse material over a wider geographical region, generally impacting more people and creating larger long term dose and cleanup costs. A ground level release height (0 m) shows a decrease in dose risk and cost risk of 2% and 2%, respectively. A release from the top of containment (56.1 m) shows an increase in dose risk and cost risk of 2% and 3%, respectively. The impacts of release height assumptions are small.

The release heat sensitivity case evaluates the impact of assumptions of thermal plume effects. The base case assumed a heat content of 10 MW per plume segment, except for the intact containment release category where zero plume heat was assumed. The 10 MW per plume segment value is generally bounding for the values used in the NUREG-1150 (NRC 1990a) study as documented in NUREG/CR-4551 (NRC 1990b). Modeling plume heat increases the buoyancy effect of the released plumes and generally has similar impacts as modeling a higher release height. The sensitivity case assumed no thermal plume heat in the releases (i.e., no buoyant plumes). The impacts of assuming no plume heat is a cost risk decrease of 2%. The dose risk was marginally impacted.

F.7.3.4 DEPOSITION VELOCITY

The dry deposition velocity sensitivity case evaluates the impact of the fission product particle size as reflected in the deposition velocity parameter. The base case assumes a deposition velocity of 0.01 m/sec, consistent with the NRC recommendation documented in MACCS2 Sample Problem A (NRC 1998). The sensitivity case uses a deposition velocity of 0.003 m/sec, reflective of a smaller particle size. This 0.003 m/sec value was suggested (but not used) in the Integrated Risk Assessment for LSCS Unit 2 study (NRC 1992c) as a more appropriate value than 1 cm/sec based on published literature. The more recent NRC State-of-the-Art Reactor Consequence Study (NRC 2013b) states that the average deposition velocity used in that analysis is approximately 0.003 m/sec. Assuming a lower deposition velocity results in a decrease in the dose risk and cost risk of 1% and 31%, respectively. This decrease is attributed to smaller particles traveling further and exiting the 50-mile radius SAMA analysis region.

F.7.3.5 POPULATION SENSITIVITY

A population sensitivity case assesses the impact of population assumptions. The base case year 2043 population is uniformly increased by 30% in all grid elements of the 50-mile radius area. This change has a significant impact on the dose risk and cost risk, increasing dose risk and cost risk by 29% and 29%, respectively. This sensitivity case demonstrates a significant dependence upon population estimates. This dependence is expected given that population dose and offsite economic costs are primarily driven by the regional population.

F.7.3.6 RESETTLEMENT PLANNING SENSITIVITIES

The MACCS2 consequence modeling incorporates an “intermediate phase” which depicts the time period following the release and immediate evacuation actions (termed the “early phase”) and extends to the time when recovery efforts such as decontamination and resettlement of people are begun (termed the “long term phase”). The intermediate phase thus models the time period when decontamination and resettlement plans are being developed. MACCS2 allows the habitation of land during the intermediate phase unless projected dose criteria are exceeded, in which case individuals are relocated. MACCS2 allows an intermediate phase ranging from no intermediate phase to a maximum of one year. The intermediate phase sensitivities show significant impacts and are therefore discussed further:

- The no intermediate phase resettlement planning case is developed based on the NUREG-1150 (NRC 1990a) modeling approach. The 40% reduction in cost risk seen in the sensitivity results, however, is judged too optimistic in that the land decontamination efforts are modeled as starting one week after the accident (i.e., directly after the early phase ends), such that a significant portion of population relocation costs are omitted. For instance, the costs associated with temporary housing of interdicted individuals while decontamination strategies are developed and decontamination teams are contracted are not accounted for without an intermediate phase. It is believed that the NUREG-1150 studies omitted the intermediate phase because the intermediate phase coding was not validated at that time (NRC 1998). A competing factor is that the population dose increases (12% increase over the base case) because people are allowed to re-occupy the decontaminated land sooner.
- The 1 year intermediate phase resettlement planning case is developed based on the maximum length of time allowed by MACCS2 for the intermediate phase. A long intermediate phase can be unrealistic in that re-occupation of contaminated land is not performed during this phase even if contamination levels decrease (by natural radioactive decay and weathering) to levels which would allow it (i.e., resettlement is evaluated as part of the long term phase, not the intermediate phase). Therefore population relocation costs may be overestimated using a long (i.e., one year) intermediate phase. An intermediate phase of one year shows a 40% increase in cost risk estimates compared with the base case selection of 6 months. The population dose decreased by 10% with a longer intermediate phase due to later resettlement on decontaminated land.

The six month intermediate phase (base case) is judged to be a best estimate approach in that it provides reasonable time for both decontamination and resettlement planning to be performed. The sensitivity cases demonstrate that the six month value used in the base case provides mid-range results for the modeling choices available.

F.7.3.7 GENERIC ECONOMIC INPUTS SENSITIVITY

MACCS2 requires certain site-specific economic data (e.g., fraction of land devoted to farming, annual farm sales, fraction of farm sales resulting from dairy production, and property value of farm and non-farm land) for each of the 160 spatial elements. The site-specific base case values are calculated based on regional economic data.

In addition to these site specific values, standardized economic data are utilized by MACCS2 to address costs associated with per diem living expenses (applied to owners of interdicted properties and relocated populations), relocation costs (for owners of interdicted properties), and decontamination costs. For the LSCS base case, these generic costs are based on values used in the NUREG-1150 study (NRC 1990a) as documented in the NUREG/CR-4551 (NRC 1990b) and updated to July 2013 using the consumer price index.

This sensitivity case is performed to determine the variability in population dose risk and cost risk based on changes to these standardized values. The sensitivity case increases key standardized economic parameters as identified in Table F.7-1. In general, the inputs were arbitrarily increased by factor of 2.0. The increase in these economic parameters resulted in an increase in cost risk of 54% and a decrease in dose risk of about 3%. A significant increase in cost risk is expected since population relocation and decontamination costs are major contributors to total cost as calculated by MACCS2.

F.7.3.8 RATE OF RETURN SENSITIVITIES

One of the economic cost components included in the MACCS2-calculated cost result is the financial loss associated with property and associated improvements (e.g., buildings) not achieving their expected annual rate of return during interdiction periods. A piece of land that is interdicted (i.e., not occupied) for a period of years will not achieve the historical rate of return or the rate of return achieved by other non-impacted properties during the interdiction period. This lack of expected return is an economic loss for the owner / society. The base case assumes a 7% expected rate of return, consistent with NRC guidance (NRC 2004a). A sensitivity case using a 3% expected rate of return shows a decrease in the expected cost risk of approximately 9%. This decrease in cost risk associated with the lower rate or return is expected since there is a lower expectation associated with the land’s return on investment. A sensitivity case using a 12% expected rate of return, the value used in NUREG-1150 MACCS2 analyses (NRC 1990b), shows an increase cost risk of approximately 11%. For both sensitivity cases the dose risk changes are minor (<=1%).

F.7.3.9 VALUE OF FARM AND NON-FARM WEALTH SENSITIVITY

This sensitivity assesses the impact of doubling the average farm and non-farm wealth values for the area surrounding LSCS. The Base case wealth PERCHR3 values, 11,937 $/hectare for farm wealth and 283,637 $/person for non-farm wealth, were increased to 23,874 $/hectare and 567,274 $/person, respectively. This increase in the wealth parameters results in a cost risk increase of 59%. The increase in the dose risk is less than 0.5%. The cost risk increases significantly because on a per-person and per-farm basis, more wealth is being impacted. This sensitivity indicates there is significant cost risk dependency associated with farm and non-farm wealth parameters.

F.7.3.10 IMPACT ON SAMA ANALYSIS

Several different Level 3 input parameters are examined as part of the LSCS MACCS2 sensitivity analysis. The primary reason for performing these sensitivity runs is to identify any reasonable changes that could be made to the Level 3 input parameters that would impact the conclusions of the SAMA analysis. While the table in Section F.7.3 summarizes the changes to the dose-risk and OECR estimates for each sensitivity case, it is prudent to consider if any of these changes would result in the retention of the SAMAs that were screened using the baseline results.

Of all the MACCS2 sensitivity cases, the largest dose-risk increase, 29%, occurred in the Population (Year 2043 population uniformly increased 30%) case. The largest OECR increase, 59%, occurred in the Value of Farm and Non-Farm Wealth Input sensitivity case (doubling of farm and non-farm wealth input values). While these changes are not insignificant, they are relatively small compared to the 95th percentile PRA results sensitivity in Section F.7.2, which increases the averted cost-risk values for the SAMAs by over a factor of 2. Therefore, the 95th percentile PRA results sensitivity case is considered to bound this case and no SAMAs would be retained based on this sensitivity that were not already identified in Section F.7.2.

F.7.4 IMPACT OF THE RELIABLE HARD PIPE VENT

The installation of the reliable hard pipe containment vent (SAMA 1) is planned for LSCS, but it was not implemented at the time the SAMA analysis was performed. Accordingly, the PRA model used for this analysis does not credit the hard pipe vent. However, because the hard pipe vent will be in place during the period of extended operation, a sensitivity analysis was performed to identify how the hard pipe vent would impact the SAMA analysis. In order to do this, the SAMA 1 model was used as the new “base” model and the Phase 2 screening analyses were re-performed relative to that model for those SAMAs that were identified as potentially cost-beneficial in section F.7.2. Because implementation of the hard pipe vent reduces risk and would not increase the benefit of any SAMAs, the impact on the SAMAs that were determined to not be cost-beneficial was not examined as part of this sensitivity.

Use of the SAMA 1 model as the base case resulted in a decrease in the MACR from $5,657,600 to $3,359,200, which is based on the PRA results documented in Section F.6.1 and the rounding up of the internal events cost-risk in the same manner as the original base case. It was assumed that the change in the baseline PRA results did not impact either the 95th percentile or the external events multiplier. The same factors that were used in the baseline analysis were retained in this analysis to account for the impact of the external events contributions and uncertainty.

The impact on the Phase 2 analysis was determined by performing the calculation/model changes identified for each SAMA in conjunction with the changes identified for SAMA 1. The following table provides a comparison of the Phase 2 results for the nominal plant configuration to the configuration in which the reliable hard pipe containment vent has been implemented. As documented in the "Change in Cost Effectiveness?" column, implementation of the hard pipe vent would make the net values of SAMAs 8, 14, 16, and 21 negative, such that they would no longer be considered as potentially cost-beneficial enhancements.

Impact of Assuming Implementation of the Hard Pipe Vent for the SAMA Base Case

SAMA ID	Implementation Cost (per unit)	Averted Cost Risk (95th percentile)	Net Value (Base)	Averted Cost Risk (95th percentile, SAMA 1 as Base Case)	Net Value (95th percentile, SAMA 1 as Base Case)	Change in Cost Effectiveness?
SAMA 2	$400,000	$2,794,130	$2,394,130	$1,904,713	$1,504,713	No
SAMA 3	$1,000,000	$2,001,236	$1,001,236	$2,001,236	$1,001,236	NA
SAMA 4	$635,242	$1,331,632	$696,390	$1,320,438	$685,196	No
SAMA 5	$400,000	$761,177	$361,177	$746,922	$346,922	No
SAMA 8	$400,000	$518,287	$118,287	$76,693	-$323,307	Yes
SAMA 9	$115,000	$444,831	$329,831	$203,409	$88,409	No
SAMA 10	$260,219	$2,585,201	$2,324,982	$1,891,527	$1,631,308	No
SAMA 14	$489,277	$886,324	$397,047	$300,724	-$188,554	Yes
SAMA 15	$1,370,000	$6,751,424	$5,381,424	$3,893,499	$2,523,499	No
SAMA 16	$475,000	$1,697,365	$1,222,365	$87,042	-$387,958	Yes
SAMA 18	$649,194	$1,198,575	$549,381	$711,546	$62,352	No
SAMA 19	$2,900,000	$6,848,449	$3,948,449	$3,989,354	$1,089,354	No
SAMA 21	$1,481,002	$1,484,531	$3,529	$1,473,814	-$7,188	Yes
SAMA 23	$1,370,000	$5,907,932	$4,537,932	$2,027,055	$657,055	No
SAMA 25	$112,000	$185,191	$73,191	$134,771	$22,771	No

F.8 CONCLUSIONS

Using a SAMA methodology consistent with NEI 05-01, SAMAs 2, 9, 10, 15, 16, 19, and 23 were found to be potentially cost-beneficial in the baseline analysis.

When the 95th percentile PRA results are considered, SAMAs 3, 4, 5, 8, 14, 18, 21, and 25 are also potentially cost-beneficial.

None of the SAMAs identified as potentially cost-beneficial are aging related.

F.8.1 OPTIMAL SAMA SET

While many SAMAs are potentially cost-beneficial for LSCS when considered independently, it should be noted that many SAMAs address similar areas of risk. Implementation of one SAMA may result in a change in the potential benefits of the remaining SAMAs, such that they are no longer cost-beneficial. Review of the potentially cost-beneficial SAMAs can help identify an "optimal" set of SAMAs for implementation; that is, a reduced set of SAMAs that will address the largest risk contributors for the site. For example, the reliable hard pipe containment vent (SAMA 1) is required to be implemented and should be considered as complete for any future considerations. Beginning with this plant enhancement, the remaining set of SAMAs can be reviewed to identify those that would mitigate the contributors not addressed by SAMA 1. It is recognized that there are different combinations of SAMAs that could achieve similar results, but this is a demonstration of a potential approach to interpreting the results of the cost benefit analysis.

Section F.7.4 documents those SAMAs that would remain cost-beneficial after implementation of SAMA 1, but many of those SAMAs address the same areas of risk as other SAMAs and implementation of one would have an impact on the remaining SAMAs. Generally, implementing one SAMA in a group of functionally similar SAMAs would render the remaining SAMAs in the group non-cost-beneficial. The following table categorizes the potentially cost-beneficial SAMAs from Section F.7.4 and discusses the implications of SAMA implementation.

Impact of SAMA Implementation by Functional Group

SAMA Functional Group	SAMA Title	Discussion
Containment Heat Removal/Pressure Control	SAMA 2: Automate Suppression Pool Cooling SAMA 3: Passive Vent Path	As with SBLC initiation and MSIV low level isolation logic bypass, containment venting and SPC initiation are manual actions that are treated in the PRA with dependent failure terms. Implementation of either SAMA would render the remaining SAMA non-cost-beneficial. Both of these SAMAs, however, reduce the control the operators have over plant equipment. The negative impacts of implementation not considered in the PRA model should be given consideration. In addition, the risk reductions associated with these SAMAs are driven by joint human error probabilities, which carry with them a significant degree of uncertainty due to limitations in modeling capabilities. Suppression pool cooling initiation and containment venting are well known and highly trained actions that are considered to be highly reliable and the benefits shown in this analysis for these SAMAs should be considered with these facts in mind.
ATWS Mitigation	SAMA 4: Install a Keylock MSIV Low Level Isolation Bypass Switch SAMA 5: Automate SBLC Injection	There is some overlap in these SAMAs because SBLC initiation and MSIV low level isolation logic bypass are manual actions. The risk model includes dependent failures of both actions and automation of one of the functions would remove the dependent impacts, which are larger than the independent failures of both actions. If SAMA 4 were implemented, SAMA 5 would no longer be cost-beneficial. Implementation of SAMA 5 would reduce the benefit of SAMA 4, but not to the degree where SAMA 4 would not be considered to be potentially cost-beneficial.
Internal Flood Mitigation	SAMA 9: Develop Flood Zone Specific Procedures	This SAMA addresses flood risk and prevents equipment loss that leads to SBO scenarios. Implementation of other potentially cost-beneficial SAMAs would not address this risk, but FLEX changes, such as the installation of a 480V AC generator, would impact the SBO sequences addressed by this SAMA and would make it non-cost-beneficial.

Impact of SAMA Implementation by Functional Group

SAMA Functional Group	SAMA Title	Discussion
RPV Makeup	SAMA 10: Change the Logic to Close the Turbine Driven Feedwater Pump Discharge Valves When the Pumps are Not Running	The addition of an alternate injection source will generally yield a significant risk reduction for a plant. In this case, there is a significant overlap in SAMAs 15 and 19 as they address ISLOCA risk. SAMAs 10, 18, and 23 do not address unisolated ISLOCAs, but do provide injection for other scenarios. Implementation of SAMA 15 would provide almost all of the benefit of SAMA 19 for significantly less cost and would also address most of the scenarios addressed by SAMAs 10, 18, and 23.
	SAMA 15: Tie RHRSW to the LPCS System for ISLOCA Mitigation	
	SAMA 18: Improve the Connection Between the Fire Protection and Feedwater Systems	
	SAMA 19: Provide Remote Alignment Capability of RHRSW to the LPCS System for LOCA Mitigation	
	SAMA 23: Enhance Fuel Pool Emergency Makeup Pump and Connection	
Other	SAMA 25: Periodic Training on Water Hammer Scenarios Resulting from a False LOCA Signal	This is a relatively low cost SAMA that would prevent a break outside of containment scenario. SAMA 15 could potentially address these scenarios and if it were implemented, SAMA 25 would not likely remain cost effective.

While a large number of SAMAs can be considered potentially cost-beneficial for LSCS when considered independently, there is a smaller subset of SAMAs that, if implemented, would render the remaining SAMAs “not cost-beneficial”. This subset consists of SAMAs 2, 4, 9, and 15.

F.9 TABLES

Table F.2-1
LSCS PRA Model Update History

Model Change description	Rev.	Date	CDF	LERF	Comments
IPE	IPE	04/94	4.41E-05[(1)]	(Not Quantified)[(2)]	Sandia National Laboratories, under contract to the NRC, completed a level 1 and 2 PRA for LaSalle Unit 2 in 1992. This PRA was documented in the multi-volume *Analysis of the LaSalle Unit 2 Nuclear Power Plant: Risk Methods Integration and Evaluation Program (RMIEP)* (SAND92-0575 / NUREG/CR-4832). A summary of the Sandia PRA was submitted to the NRC in April 1994 as LaSalle's response to NRC Generic Letter 88-20, *Individual Plant Examination for Severe Accident Vulnerabilities (IPE)*.
Updated IPE	IPE	1996	1.0E-05[(3)]	(Not Quantified)[(2)]	The focus of this effort to address issues raised by the NRC in the 1994 IPE.
Upgrade to the IPE	1999 Rev.0	07/01/99	(See Rev. 1 below)	(See Rev. 1 below)	The purpose of the 1999 LaSalle PRA upgrade was to support plant applications. The 1999 model was documented in two revisions. Revision 0 was issued before System Manager reviews had been completed. These reviews identified corrections for several logic errors and other potential enhancements that were incorporated into Revision 1. Since the Revision 0 model was not used for any applications, the Revision 1 model is referred to as the 1999 model.
Update to the IPE	1999 Rev.1	11/01/99	8.58E-06	1.5E-06	See description of PRA model 1999 Revision 0 above.

Table F.2-1
LSCS PRA Model Update History

Model Change description	Rev.	Date	CDF	LERF	Comments
Upgrade of model for Regulatory Applications	2000A	01/19/00	5.90E-06	1.0E-06	The 2000A model was created in January 2000 initially to support the diesel generators allowed outage time (AOT) extension project. The 2000A model was also used for a NEI / BWROG PSA peer review in April 2000 and to support the risk informed in-service inspection (RI-ISI) project. The NEI peer review team reviewed the 2000A model and found the model suitable for regulatory applications.
Minor Enhancements	2000B	2/25/00	5.90E-06	1.0E-06	The 2000B model included minor enhancements. It was considered to be an interim model and it was not used to support any regulatory applications.
Refinements to internal flooding model and human reliability analysis	2000C	3/20/00	8.20E-06	(Not Quantified)(4)	The 2000C model incorporated changes to the 2000B model based on a revised Turbine Building flood model and an updated LaSalle human reliability analysis (HRA). This model was used to support sensitivity studies performed for the final diesel generators AOT Technical Specification licensing amendment change request
Update to incorporate new data	2001A	08/01/01	5.70E-06	6.72E-07	The 2001A interim model was developed to revise several internal flooding initiating event frequencies based on implementing a pipe inspection program; revise the SCRAM failure probabilities based on new industry data; incorporate updated service water pump success criteria based on LaSalle historical operating practices; and, incorporate other minor enhancements.
Periodic Update in accordance with EGC PRA process	2003A	06/19/03	6.64E-06	3.56E-07	None
Periodic Update in accordance with EGC PRA process	2006A	01/31/07	8.08E-06	3.09E-07	The increase in CDF during the 2003A PRA update was due re-evaluation and expansion of the internal flooding analysis.

Table F.2-1
LSCS PRA Model Update History

Model Change description	Rev.	Date	CDF	LERF	Comments
Refinement of the internal flooding analysis	2006B	05/31/07	3.55E-06	3.00E-07	None
Correction of model error in RHR system fault tree	2006C	01/25/08	3.98E-06	2.97E-07	None
Periodic Update in accordance with EGC PRA process	2011A	03/23/13	2.58E-06	1.30E-07	The decrease in the CDF risk metric from 2006C model was primarily due to the following: 1. Bayesian updates of generic priors from NUREG/CR-6928 for both initiating events (transients) and component failures using the latest LaSalle specific data. 2. The deletion of loss of bus 241Y and 242Y as initiating events because loss of these buses does not result in a scram (previous model conservatism). 3. Refinement of the ECCS water hammer scenarios. 4. Crediting closure of the Reactor Building ventilation check dampers as a potential flood mitigation strategy. 5. The deletion of most coincident maintenance terms as these events did not meet the current definition of the ASME/ANS PRA Standard in that they are not “planned and repetitive.”

Table F.2-1
LSCS PRA Model Update History

Model Change description	Rev.	Date	CDF	LERF	Comments
					The decrease in the LERF risk metric was primarily due to: 1. Re-evaluating and categorization of mitigated ATWS (i.e. SLC successfully injected) scenarios with subsequent failure of containment heat removal from Class IV to Class II. 2. Correction of Basic Event 1OPPH-RX-ENVIF—probability from 1.0 to 1E-03. The 1E-03 value is realistic given that the controls/steam sensitive portion of the ADS system is not in the reactor building. 3. The revision to the probability for latest pre-existing containment failure modes (2CNHU-PREINIT) 5E-03 to 2.3E-3 to be consistent with current industry information in EPRI TR101824.
Model expansion from LERF to a full Level 2	2013A	07/24/14	2.58E-06	1.42E-07	Issuance of an application specific model for use in the Severe Accident Mitigation Alternatives (SAMA) Analysis.

Table F.2-2
LSCS 2013A PRA LEVEL 1 CDF CONTRIBUTION BY INITIATING EVENT
(CDF = 2.58E-06/yr at 1E-12/yr TRUNCATION)

Basic Event ID	Description	Frequency (/cr yr)	F-V	Total CDF (/yr)	IE Contrib. CDF (/yr)	CCDP
%TT	TURBINE TRIP WITH BYPASS INITIATING EVENT	7.98E-01	2.18E-01	2.58E-06	5.62E-07	7.32E-07
%DLOOP	DUAL UNIT LOSS OF OFF-SITE POWER INITIATING EVENT	7.95E-03	1.19E-01	2.58E-06	3.07E-07	4.01E-05
%TIA	LOSS OF INSTRUMENT AIR INITIATING EVENT	9.92E-03	1.08E-01	2.58E-06	2.78E-07	2.92E-05
%TC	LOSS OF CONDENSER VACUUM INITIATING EVENT	1.33E-01	1.03E-01	2.58E-06	2.66E-07	2.08E-06
%FSRB12	FPS PIPE RUPTURE IN REACTOR BLDG.	1.05E-04	7.33E-02	2.58E-06	1.89E-07	1.87E-03
%TM	MSIV CLOSURE INITIATING EVENT	5.01E-02	5.30E-02	2.58E-06	1.37E-07	2.83E-06
%TBCCWFACTOR	LOSS OF TBCCW INITIATING EVENT	1.00E+00	4.56E-02	2.58E-06	1.18E-07	1.22E-07
%TF	LOSS OF FEEDWATER INITIATING EVENT	5.65E-02	4.45E-02	2.58E-06	1.15E-07	2.11E-06
%LOOP	LOSS OF OFF-SITE POWER INITIATING EVENT	1.07E-02	2.81E-02	2.58E-06	7.24E-08	7.04E-06
%MS	MANUAL SHUTDOWN INITIATING EVENT	1.01E+00	2.30E-02	2.58E-06	5.93E-08	6.10E-08
%TI	INADVERTENTLY OPEN RELIEF VALVE INITIATING EVENT	2.16E-02	2.27E-02	2.58E-06	5.85E-08	2.82E-06
%TDCA	LOSS OF 125 VDC BUS 2A INITIATING EVENT	5.70E-04	1.96E-02	2.58E-06	5.05E-08	9.21E-05
%TDCAB	LOSS OF 125 VDC BUS 2A AND 2B INITIATING EVENT	3.42E-07	1.53E-02	2.58E-06	3.94E-08	1.20E-01
%ISLOCA-SDC	SDC SUCTION LINE ISLOCA	3.80E-08	1.42E-02	2.58E-06	3.66E-08	1.00E+00
%S2-WA	INIT: SMALL BREAK LOCA - BELOW CORE INSIDE DRYWELL	3.67E-03	1.10E-02	2.58E-06	2.84E-08	8.03E-06

Table F.2-2
LSCS 2013A PRA LEVEL 1 CDF CONTRIBUTION BY INITIATING EVENT
(CDF = 2.58E-06/yr at 1E-12/yr TRUNCATION)

Basic Event ID	Description	Frequency (/cr yr)	F-V	Total CDF (/yr)	IE Contrib. CDF (/yr)	CCDP
%S1-WA	INIT: OTHER MEDIUM BREAK LOCA - BELOW CORE	9.37E-05	8.80E-03	2.58E-06	2.27E-08	2.52E-04
%TDCB	LOSS OF 125 VDC BUS 2B INITIATING EVENT	5.70E-04	8.18E-03	2.58E-06	2.11E-08	3.85E-05
%S1-LP	INIT: MEDIUM BREAK LOCA - BELOW CORE IN LPCI LINE	1.62E-04	7.53E-03	2.58E-06	1.94E-08	1.25E-04
%S2-ST	INIT: SMALL BREAK LOCA - ABOVE CORE INSIDE DRYWELL	3.71E-03	7.21E-03	2.58E-06	1.86E-08	5.21E-06
%TSWFACTOR	LOSS OF SERVICE WATER INITIATING EVENT	1.00E+00	5.76E-03	2.58E-06	1.48E-08	1.54E-08
%RBCCWFACTOR	LOSS OF RBCCW INITIATING EVENT	1.00E+00	5.70E-03	2.58E-06	1.47E-08	1.53E-08
%S1-ST	INIT: OTHER MEDIUM BREAK LOCA - ABOVE CORE	3.09E-04	5.60E-03	2.58E-06	1.44E-08	4.86E-05
%A-ST	LARGE LOCA ABOVE TAF	2.29E-05	3.75E-03	2.58E-06	9.67E-09	4.39E-04
%FSDG1	CSCS PIPE RUPTURE IN DIV. 3 CSCS ROOM	4.06E-07	3.15E-03	2.58E-06	8.12E-09	2.08E-02
%ISLOCA-RHRA	RHR A INJECTION LINE ISLOCA	7.50E-09	2.67E-03	2.58E-06	6.88E-09	9.54E-01
%ISLOCA-RHRA-S	RHR A SDC RETURN LINE ISLOCA	7.50E-09	2.67E-03	2.58E-06	6.88E-09	9.54E-01
%ISLOCA-RHRB	RHR B INJECTION LINE ISLOCA	7.50E-09	2.67E-03	2.58E-06	6.88E-09	9.54E-01
%ISLOCA-RHRB-S	RHR B SDC RETURN LINE ISLOCA	7.50E-09	2.67E-03	2.58E-06	6.88E-09	9.54E-01
%ISLOCA-LPCS	LPCS INJECTION LINE ISLOCA	7.50E-09	2.66E-03	2.58E-06	6.86E-09	9.50E-01
%ISLOCA-RHRC	RHR C INJECTION LINE ISLOCA	7.50E-09	2.66E-03	2.58E-06	6.86E-09	9.50E-01
%A-LP	LARGE LOCA IN LPCI LINE	1.47E-05	2.50E-03	2.58E-06	6.44E-09	4.56E-04
%FSRB2	SW PIPE RUPTURE IN RB AREA 3G	5.07E-07	2.09E-03	2.58E-06	5.39E-09	1.10E-02

Table F.2-2
LSCS 2013A PRA LEVEL 1 CDF CONTRIBUTION BY INITIATING EVENT
(CDF = 2.58E-06/yr at 1E-12/yr TRUNCATION)

Basic Event ID	Description	Frequency (/cr yr)	F-V	Total CDF (/yr)	IE Contrib. CDF (/yr)	CCDP
%A-ADS	INADVERTANT ADS	1.00E-05	1.64E-03	2.58E-06	4.23E-09	4.39E-04
%TAC252	LOSS OF 6.9 kVAC BUS 252 INITIATING EVENT	2.18E-03	1.59E-03	2.58E-06	4.10E-09	1.95E-06
%FSRB5	DGCW 2A PIPE RUPTURE IN U2 RACEWAY	3.37E-06	1.58E-03	2.58E-06	4.07E-09	1.26E-03
%A-WA	LARGE LOCA BELOW TAF	7.52E-06	1.50E-03	2.58E-06	3.87E-09	5.34E-04
%BOC-MS	BREAK OUTSIDE CONTAINMENT IN MAIN STEAM LINE	1.62E-08	1.46E-03	2.58E-06	3.76E-09	2.41E-01
%FSTB2	FPS PIPE RUPTURE IN TURBINE BLDG.	1.05E-04	1.44E-03	2.58E-06	3.71E-09	3.67E-05
%FSTB4	CW COMPONENT RUPTURE IN CONDENSER PIT	2.80E-03	1.40E-03	2.58E-06	3.61E-09	1.34E-06
%FSRB6	DGCW 2B PIPE RUPTURE IN U2 RACEWAY	4.21E-06	1.38E-03	2.58E-06	3.56E-09	8.78E-04
%FSRB3	SW PIPE RUPTURE IN RB AREA 3B1, 3B2, 3C, 3D OR 3F	2.20E-06	1.23E-03	2.58E-06	3.17E-09	1.50E-03
%S1-HP	INIT: MEDIUM BREAK LOCA - ABOVE CORE IN HPCS LINE	3.01E-05	9.65E-04	2.58E-06	2.49E-09	8.59E-05
%FSTB8	CW MANWAY RUPTURE OUTSIDE CONDENSER PIT	2.31E-07	7.95E-04	2.58E-06	2.05E-09	9.22E-03
%FSRB9	DGCW 2A PIPE RUPTURE IN U2 RHR B/C CORNER ROOM	1.69E-06	7.87E-04	2.58E-06	2.03E-09	1.25E-03
%R	EXCESSIVE LARGE LOCA INITIATING EVENT	1.00E-08	7.50E-04	2.58E-06	1.93E-09	2.01E-01
%BOC-RC	BREAK OUTSIDE CONTAINMENT IN RCIC DISCHARGE LINE	7.40E-09	6.67E-04	2.58E-06	1.72E-09	2.42E-01

Table F.2-2
LSCS 2013A PRA LEVEL 1 CDF CONTRIBUTION BY INITIATING EVENT
(CDF = 2.58E-06/yr at 1E-12/yr TRUNCATION)

Basic Event ID	Description	Frequency (/cr yr)	F-V	Total CDF (/yr)	IE Contrib. CDF (/yr)	CCDP
%BOC-RW	BREAK OUTSIDE CONTAINMENT IN RWCU LINE	7.40E-09	6.67E-04	2.58E-06	1.72E-09	2.42E-01
%A-HP	LARGE LOCA IN HPCS LINE	3.64E-06	5.95E-04	2.58E-06	1.53E-09	4.38E-04
%FSTB9	UNISOLABLE SW PIPE RUPTURE OUTSIDE CONDENSER PIT	3.04E-07	5.92E-04	2.58E-06	1.53E-09	5.22E-03
%TAC241X	LOSS OF 4.16 kVAC BUS 241X INITIATING EVENT	2.18E-03	5.73E-04	2.58E-06	1.48E-09	7.04E-07
%TAC242X	LOSS OF 4.16kVAC BUS 242X INITIATING EVENT	2.18E-03	5.27E-04	2.58E-06	1.36E-09	6.48E-07
%TAC251	LOSS OF 6.9 kVAC BUS 251 INITIATING EVENT	2.18E-03	5.16E-04	2.58E-06	1.33E-09	6.34E-07
%A-CS	LARGE LOCA IN LPCS LINE	3.15E-06	5.15E-04	2.58E-06	1.33E-09	4.38E-04
%FSAB2	FPS PIPE RUPTURE IN AUXILIARY BLDG.	3.49E-05	4.69E-04	2.58E-06	1.21E-09	3.60E-05
%FSTB7	SW STANDPIPE RUPTURE OUTSIDE CONDENSER PIT	2.21E-07	4.29E-04	2.58E-06	1.11E-09	5.20E-03
%S1-CS	INIT: MEDIUM BREAK LOCA - ABOVE CORE IN LPCS LINE	2.18E-05	4.10E-04	2.58E-06	1.06E-09	5.04E-05
%FSDG2	FPS PIPE RUPTURE IN DIV. 3 CSCS ROOM	2.79E-05	3.73E-04	2.58E-06	9.62E-10	3.58E-05
%FSRB4	DGCW 0A PIPE RUPTURE IN U2 RACEWAY	1.30E-06	3.66E-04	2.58E-06	9.43E-10	7.54E-04
%FSRB1	SW PIPE RUPTURE IN RB AREA 3E	2.70E-07	2.41E-04	2.58E-06	6.21E-10	2.39E-03
%FSRB8	DGCW 0A PIPE RUPTURE IN U2 LPCS/RCIC CORNER ROOM	6.50E-07	1.83E-04	2.58E-06	4.72E-10	7.54E-04
%FSTB11	DGCW 2B PIPE RUPTURE IN TB BASEMENT	8.43E-06	1.31E-04	2.58E-06	3.38E-10	4.16E-05

Table F.2-2
LSCS 2013A PRA LEVEL 1 CDF CONTRIBUTION BY INITIATING EVENT
(CDF = 2.58E-06/yr at 1E-12/yr TRUNCATION)

Basic Event ID	Description	Frequency (/cr yr)	F-V	Total CDF (/yr)	IE Contrib. CDF (/yr)	CCDP
%FSTB5	DEICING PIPE RUPTURE (UNIT 2)	3.17E-08	1.03E-04	2.58E-06	2.66E-10	8.71E-03
%FSTB6	DEICING PIPE RUPTURE (UNIT 1)	3.17E-08	1.03E-04	2.58E-06	2.66E-10	8.71E-03
%TRLA	MEDIUM RANGE RX WATER REFERENCE LEG A LINE BREAK	2.24E-03	1.02E-04	2.58E-06	2.63E-10	1.22E-07
%TRLB	MEDIUM RANGE RX WATER REFERENCE LEG B LINE BREAK	2.24E-03	1.02E-04	2.58E-06	2.63E-10	1.22E-07
%FSRB11	DIV. 1 RHRSW PIPE RUPTURE IN U2 RHR A CORNER ROOM	2.54E-07	7.15E-05	2.58E-06	1.84E-10	7.54E-04
%BOC-FW	BREAK OUTSIDE CONTAINMENT IN FW DISCHARGE LINE	5.50E-10	4.96E-05	2.58E-06	1.28E-10	2.42E-01
%FSRB10	DIV. 2 RHRSW PIPE RUPTURE IN U2 RHR B/C CORNER ROOM	2.54E-07	4.72E-05	2.58E-06	1.22E-10	4.98E-04
%FSRB7	DIV. 1 RHRSW PIPE RUPTURE IN U2 RACEWAY	1.35E-07	4.58E-05	2.58E-06	1.18E-10	9.09E-04
%FSAB1	SW PIPE RUPTURE IN AUXILIARY BLDG.	3.13E-06	1.17E-05	2.58E-06	3.02E-11	1.00E-05
%BOC-HP	BREAK OUTSIDE CONTAINMENT IN HPCS LINE	1.00E-10	8.73E-06	2.58E-06	2.25E-11	2.34E-01
%FSTB3	CW PIPE RUPTURE IN CONDENSER PIT	2.28E-05	5.74E-06	2.58E-06	1.48E-11	6.75E-07

Table F.2-3
SUMMARY OF LS213A CDF BY ACCIDENT SEQUENCE SUBCLASS
(CDF = 2.58E-06/yr at 1E-12/yr TRUNCATION)

Accident Class Designator	Subclass	Definition	Model 2013A (per Yr)
Class I	A	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high.	8.46E-08
	B	Accident sequences involving a station blackout and loss of coolant inventory makeup. (Class IBE is defined as “Early” Station Blackout events with core damage at less than 4 hours. Class IBL is defined as “Late” Station Blackout events with core damage at greater than 4 hours.)	IBE 3.43E-07 IBL 2.94E-07
	C	Accident sequences involving a loss of coolant inventory induced by an ATWS sequence with containment intact.	1.67E-07
	D	Accident sequences involving a loss of coolant inventory makeup in which reactor pressure has been successfully reduced to 200 psi.	3.53E-08
	E	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high and DC power is unavailable.	(Grouped with Class IA)
Class II	A	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	1.03E-06
	L	Accident sequences involving a loss of containment heat removal with the RPV breached but no initial core damage; core damage induced post containment failure. (Not used)	
	T	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage induced post high containment pressure.	
	V	Class IIA and III except that the vent operates as designed; loss of makeup occurs at some time following vent initiation. Suppression pool saturated but intact.	

Table F.2-3
SUMMARY OF LS213A CDF BY ACCIDENT SEQUENCE SUBCLASS
(CDF = 2.58E-06/yr at 1E-12/yr TRUNCATION)

Accident Class Designator	Subclass	Definition	Model 2013A (per Yr)
Class III (LOCA)	A	Accident sequences leading to core damage conditions initiated by vessel rupture where the containment integrity is not breached in the initial time phase of the accident.	9.62E-10
	B	Accident sequences initiated or resulting in small or medium LOCAs for which the reactor cannot be depressurized prior to core damage occurring.	1.48E-08
	C	Accident sequences initiated or resulting in medium or large LOCAs for which the reactor is a low pressure and no effective injection is available.	9.98E-09
	D	Accident sequences which are initiated by a LOCA or RPV failure and for which the vapor suppression system is inadequate, challenging the containment integrity with subsequent failure of makeup systems.	2.68E-08
Class IV (ATWS)	A	Accident sequences involving failure of adequate shutdown reactivity with the RPV initially intact; core damage induced post containment failure.	4.87E-07
	L	Accident sequences involving a failure of adequate shutdown reactivity with the RPV initially breached (e.g. LOCA or SORV); core damage induced post containment failure.	
	T	Accident sequences involving a failure of adequate shutdown reactivity with the RPV initially intact, core damage induced post high containment pressure. (Not used)	
	V	Class IVA or IVL except that the vent operates as designed; loss of makeup occurs at some time following vent initiation. Suppression pool saturated but intact. (Not used)	
Class V	---	Unisolated LOCA outside containment.	8.33E-08
		Total	2.58E-06

Table F.2-4
Release Severity And Timing Classification Matrix

Release Severity		Release Timing	
Classification Category	**Cs Iodide % in Release**	**Classification Category**	**Time of Initial Release[2] Relative to Time for General Emergency Declaration**
High (H)	Greater than 10	Late (L)	Greater than 24 hours
Medium or Moderate (M)	1 to 10	Intermediate (I)	5 to 24 hours
Low (L)	0.1 to 1	Early (E)	Less than 5 hours
Low-low (LL)	Less than 0.1		
Intact (OK)	Leakage		

Table F.2-5
Release Category Matrix

Time of Release	Magnitude of Release			
	H	**M**	**L**	**LL**
E	H/E	M/E	L/E	LL/E
I	H/I	M/I	L/I	LL/I
L	H/L	M/L	L/L	LL/L

Table F.2-6
Summary Of LSCS Level 2 Release Categories (/Yr) (1), (2), (3)

Class	CDF	Intact	LL/E	LL/I	LL/L	L/E	L/I	L/L	M/E	M/I	M/L	H/E	H/I	H/L	Total Release
IA	8.46E-08	1.18E-08	N/A	0.00E+00	N/A	3.68E-08	1.08E-08	N/A	1.10E-09	1.67E-08	N/A	7.34E-09	2.05E-10	N/A	7.28E-08
IBE	3.43E-07	2.96E-07	N/A	0.00E+00	N/A	1.85E-08	1.28E-08	N/A	3.07E-09	7.53E-09	N/A	4.53E-09	7.40E-10	N/A	4.72E-08
IBL	2.94E-07	1.57E-07	N/A	0.00E+00	N/A	N/A	8.33E-08	N/A	N/A	3.72E-08	N/A	N/A	1.63E-08	N/A	1.37E-07
IC	1.67E-07	1.44E-07	N/A	0.00E+00	N/A	1.08E-08	9.11E-09	N/A	1.60E-09	5.63E-11	N/A	1.57E-09	0.00E+00	N/A	2.31E-08
ID	3.53E-08	2.98E-09	N/A	0.00E+00	N/A	2.72E-08	0.00E+00	N/A	0.00E+00	4.92E-09	N/A	2.13E-10	0.00E+00	N/A	3.23E-08
II	8.23E-07	2.70E-08	N/A	0.00E+00	N/A	N/A	0.00E+00	N/A	N/A	7.94E-07	N/A	N/A	1.75E-09	N/A	7.96E-07
IIE	4.33E-08	1.77E-08	0.00E+00	N/A	N/A	0.00E+00	N/A	N/A	2.56E-08	N/A	N/A	0.00E+00	N/A	N/A	2.56E-08
IIV	1.60E-07	6.54E-08	N/A	N/A	N/A	N/A	2.65E-08	N/A	N/A	6.79E-08	N/A	N/A	1.62E-10	N/A	9.46E-08
IIVE	8.46E-09	5.86E-09	N/A	N/A	N/A	5.67E-10	N/A	N/A	2.03E-09	N/A	N/A	0.00E+00	N/A	N/A	2.59E-09
IIIA	9.62E-10	2.37E-10	N/A	0.00E+00	N/A	0.00E+00	6.99E-10	N/A	8.82E-12	0.00E+00	N/A	1.73E-11	N/A	N/A	7.25E-10
IIIB	1.49E-08	1.33E-08	N/A	0.00E+00	N/A	0.00E+00	1.32E-09	N/A	1.49E-11	0.00E+00	N/A	2.57E-10	N/A	N/A	1.59E-09
IIIC	9.98E-09	0.00E+00	N/A	0.00E+00	N/A	6.16E-09	4.58E-10	N/A	3.09E-09	2.63E-10	N/A	1.85E-10	N/A	N/A	1.02E-08
IIID	2.68E-08	0.00E+00	N/A	N/A	0.00E+00	0.00E+00	N/A	N/A	0.00E+00	N/A	N/A	2.69E-08	N/A	N/A	2.69E-08
IV	4.88E-07	0.00E+00	0.00E+00	N/A	N/A	2.93E-07	N/A	N/A	1.77E-07	N/A	N/A	1.83E-08	N/A	N/A	4.89E-07
V	8.32E-08	0.00E+00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	8.32E-08	N/A	N/A	8.32E-08
Total	2.58E-06	7.45E-07	0.00E+00	0.00E+00	0.00E+00	3.88E-07	1.45E-07	N/A	2.14E-07	9.27E-07	N/A	1.42E-07	1.90E-08	N/A	1.84E-06

(1) Based on results of PRAQuant results at the sequence level. Level 2 quantified at a truncation value of 1E-12/yr.

(2) N/A indicates that the accident class did not contribute to release of that specific category.

(3) Numerical differences in column totals may occur due to rounding.

Table F.2-7
Open LSCS PRA 2008 Peer Review Findings and Supporting Requirements Assigned Less Than Capability Category II

Supporting Requirements	Description of Gap[7]	Peer Review Assessment	Impact on SAMA Analysis
AS-B2	The modeling of Station Blackout assumes that, following recovery of offsite power, sufficient mitigating systems will be available to prevent core damage. The availability of mitigating systems should be explicitly considered in the event tree modeling.	Finding	Non-significant quantitative impact. This is an issue related to enhanced modeling for SBO scenarios. PRA results are dominated by failure to recover offsite power. Modeling refinements may result in improved level of detail of results. No significant impact on the SAMA analysis.
SC-B5	While the LS-PSA-003 notebook provides some selected comparison of RMEIP MELCOR results to more recent MAAP runs, there is no documented comparison of how the LSCS success criteria compare to those used for sister plants or other similar comparisons as required for this SR. However, the success criteria used for LSCS appear to be consistent with those of other similar BWRs. The LS-PSA-003 documentation should be enhanced to include a section that compares the LSCS success criteria to those used in the PRAs of other similar BWRs.	Supporting Requirement Not Met	Documentation issue. No quantitative impact. The LSCS PRA Success Criteria Notebook compares MAAP and MELCOR runs. The peer review team desired more comparisons with other plants and other codes. No impact on the SAMA analysis.

[7] The gap descriptions are taken from the bases and assessment fields of the LaSalle PRA 2007 Peer Review database provided to Exelon by the review team.

Table F.2-7
Open LSCS PRA 2008 Peer Review Findings and Supporting Requirements Assigned Less Than Capability Category II

Supporting Requirements	Description of Gap[7]	Peer Review Assessment	Impact on SAMA Analysis
SY-A4	System engineer interviews are documented in the respective system notebooks. Operator interviews are documented in the HRA notebook. Each system notebook contains an appendix documenting interviews with system managers, however, there is little mention (if any at all) of walkdowns performed in support of the system analyses. The impression received is that walkdowns were performed some time ago for a much earlier revision but have not been retained in the system notebooks. Interview with plant engineers has been documented. However, plant walkdown details are not provided in the SBLC, CSCS, HPCS and RCIC NBs. PERFORM plant walkdowns with system engineers AND plant operators. Better document the walkdowns performed in support of the PRA and reference those walkdowns in each system notebook to achieve CC II.	Supporting Requirement Met (CC I)	Documentation issue. No quantitative impact. The majority of the LSCS PRA System Notebooks include documented Operator Interviews and Walkdowns. The peer review team desired that every System Notebook include such documentation and that walkdowns be performed with both Ops and Systems personnel on the walkdown. No impact on the SAMA analysis.

Table F.2-7
Open LSCS PRA 2008 Peer Review Findings and Supporting Requirements Assigned Less Than Capability Category II

Supporting Requirements	Description of Gap[7]	Peer Review Assessment	Impact on SAMA Analysis
DA-C8	Basic events used to model the standby status of various plant systems use a mixture of plant-specific operational data and engineering judgment. For the Plant Service Water system and several other systems, standby estimates have been determined from procedures and operating data (see Appendix G of LS-PSA-010). For other components, assumptions are used (e.g., 50% probability of either of two pumps in a system is in standby). So, overall LSCS has some Category II attributes and some Category I attributes. Collect plant-specific data for all of the basic events that reflect standby status to meet Category II requirements.	Supporting Requirement Met (CC I)	Non-significant quantitative impact. The LSCS PRA uses primarily plant-specific information for configuration probabilities. Peer Review team desired that <u>all</u> configuration probabilities used in the PRA be based on plant-specific data. During the 2011 PRA update, plant specific data was gathered and incorporated for all risk significant systems. Plant operating practices were reviewed to incorporate standby and run times for systems with standby pumps. No significant impact on the SAMA analysis.
DA-C10	LS-PSA-010 Component Data Notebook, Appendix C, page C-24 states "No actual data or estimates for these parameters are provided by system managers. Data from the MSPI basis document, Scoping and Performance Criteria Document, and 2003 data notebook is used." However, no discussion of how surveillance tests were used is provided in the PRA. Category I is met, but it is unclear if Category II requirements are met. The documentation should describe how tests were counted to fully meet the requirements of this SR.	Supporting Requirement Met (CC I)	No quantitative impact. For the 2011 PRA update, plant specific data was obtained for all risk significant systems for the data update. This is a documentation issue pertaining to fully describing how the data is obtained and used. The issue remains open for a document enhancement. No impact on the SAMA analysis.

Table F.2-7
Open LSCS PRA 2008 Peer Review Findings and Supporting Requirements Assigned Less Than Capability Category II

Supporting Requirements	Description of Gap[7]	Peer Review Assessment	Impact on SAMA Analysis
IF-C3b	Appendix D addresses flow through drain lines (e.g., 3I4 and 3J5) and addresses doors as well. RG1.200 appends the Cat II requirements to include the potential for barrier unavailability, including maintenance. Barrier unavailability does not appear to have been discussed; however, given the nature of the major flooding scenarios it will probably make little difference. In order to meet the Cat II requirements of RG1.200 one must address potential unavailability of barriers that affect the propagation of water.	Supporting Requirement Met (CC I)	Documentation issue. No quantitative impact. Flood barrier unavailability is considered and included in the internal flood analysis. Peer review team desired to see more extensive discussions on this topic; however, the team expected any resulting changes to the model results would be non-significant. No significant impact on the SAMA analysis.

Table F.3-1
County Based Growth Rates 2000 – 2030

County	Growth Rate 2000 – 2030 Percentage
Bureau	14.8%
Cook	11.2%
DeKalb	39.4%
DuPage	14.2%
Ford	12.2%
Grundy	34.1%
Iroquois	15.7%
Kane	67.8%
Kankakee	21.6%
Kendall	55.7%
La Salle	26.8%
Lee	7.8%
Livingston	13.6%
Marshall	8.6%
Mclean	32.1%
Ogle	24.7%
Peoria	5.2%
Putnam	11.0%
Tazewell	29.0%
Will	117.3%
Woodford	31.9%

Table F.3-2
2000 and 2010 Population Comparison for Counties Within 50 miles of LSCS[8]

County	Approximate Area Fraction Within 50 Miles of LSCS	2000 CENSUS Total Population	2000 CENSUS Weighted Population	2010 Projected Total Population	2010 Projected Weighted Population	2010 CENSUS Total Population	2010 CENSUS Weighted Population
Bureau	0.65	35,561	23,115	36,427	23,678	34,978	22,736
Cook	0.08	5,386,673	430,934	5,472,429	437,794	5,194,675	415,574
DeKalb	0.65	89,118	57,927	101,735	66,128	105,160	68,354
DuPage	0.45	905,764	407,594	948,549	426,847	916,924	412,616
Ford	0.45	14,272	6,422	14,706	6,618	14,081	6,336
Grundy	1.00	37,599	37,599	41,650	41,650	50,063	50,063
Iroquois	0.30	31,386	9,416	32,524	9,757	29,718	8,915
Kane	0.55	404,834	222,659	516,914	284,303	515,269	283,398
Kankakee	0.85	104,010	88,409	110,659	94,060	113,449	96,432
Kendall	1.00	54,633	54,633	68,588	68,588	114,736	114,736
La Salle	1.00	111,700	111,700	118,385	118,385	113,924	113,924
Lee	0.60	36,118	21,671	36,554	21,932	36,031	21,619
Livingston	1.00	39,743	39,743	40,838	40,838	38,950	38,950
Marshall	0.90	13,209	11,888	13,370	12,033	12,640	11,376

8 The 50-mile population totals in this table do not match the SECPOP2000 generated 50-mile population total (see Table F.3-4) because the numbers in this table assume uniform population distribution. The intent of this table is to show that the projected year 2010 data is more conservative than the year 2010 population data (i.e., indicates a higher population) as applied in this MACCS2 analysis.

Table F.3-2
2000 and 2010 Population Comparison for Counties Within 50 miles of LSCS[8]

County	Approximate Area Fraction Within 50 Miles of LSCS	2000 CENSUS Total Population	2000 CENSUS Weighted Population	2010 Projected Total Population	2010 Projected Weighted Population	2010 CENSUS Total Population	2010 CENSUS Weighted Population
McLean	0.35	150,696	52,744	168,611	59,014	169,572	59,350
Ogle	0.03	51,119	1,534	54,704	1,641	53,497	1,605
Peoria	0.05	183,751	9,188	187,876	9,394	186,494	9,325
Putnam	1.00	6,086	6,086	6,221	6,221	6,006	6,006
Tazewell	0.01	128,175	1,282	139,616	1,396	135,394	1,354
Will	0.90	503,162	452,846	706,639	635,975	677,560	609,804
Woodford	0.80	35,529	28,423	39,362	31,490	38,664	30,931
Total	--	--	2,075,810	--	2,397,741	--	2,383,404

Table F.3-3
Included Transient and Special Facility Population Within a 10-Mile Radius of LSCS, Year 2000[9]

Sector	0-1 mile	1-2 miles	2-3 miles	3-4 miles	4-5 miles	5-10 miles	0-10 miles Total
N	0	0	20	0	1,355	0	1,375
NNE	0	0	0	0	450	598	1,048
NE	0	0	0	0	448	1,241	1,689
ENE	0	125	125	0	0	106	356
E	0	100	100	0	0	0	200
ESE	0	0	1,500	0	0	0	1,500
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	126	126
SSW	0	0	0	0	0	0	0
SW	0	0	0	0	0	229	229
WSW	0	0	0	0	0	51	51
W	0	0	0	0	0	390	390
WNW	0	0	0	0	0	104	104
NW	0	0	0	0	150	1,016	1,166
NNW	0	0	0	0	0	4,010	4,010
Total	0	225	1,745	0	2,403	7,871	12,244

[9] The year 2000 transient (includes employees), seasonal resident, and special facility population is conservatively assumed to be equivalent to the year 2010 transient (includes employees), seasonal resident, and special facility population provided in the LaSalle ETE (ARCADIS 2012).

Table F.3-4
SECPOP2000 Based Residential Population Distribution Within a 50-Mile Radius of LSCS, Year 2000

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles	50-mile Total
N	1,068	4,782	16,711	6,518	48,325	77,404
NNE	1,093	1,084	11,097	109,919	216,180	339,373
NE	2,028	7,387	7,327	145,604	364,745	527,091
ENE	277	10,459	12,728	74,790	127,463	225,717
E	236	4,254	21,318	4,738	57,297	87,843
ESE	381	1,663	2,545	5,455	30,695	40,739
SE	211	5,784	1,026	1,612	4,894	13,527
SSE	258	1,318	1,164	7,774	1,489	12,003
S	411	987	14,033	3,021	4,562	23,014
SSW	252	952	2,145	5,600	6,142	15,091
SW	291	19,153	3,231	4,415	14,464	41,554
WSW	206	1,119	2,480	4,916	11,534	20,255
W	722	1,091	8,690	5,264	4,575	20,342
WNW	443	6,446	27,688	4,455	9,707	48,739
NW	1,547	16,613	1,608	9,826	5,043	34,637
NNW	5,058	1,758	4,565	3,309	4,426	19,116
Total	14,482	84,850	138,356	397,216	911,541	1,546,445

Table F.3-5
2010 Projected Population Distribution within a 50-Mile Radius of LSCS[10]

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles	50-mile Total
N	2,589	5,160	18,766	7,737	57,458	91,710
NNE	2,317	1,288	13,927	139,048	261,145	417,725
NE	4,074	8,237	9,305	202,390	418,727	642,733
ENE	690	11,589	17,310	105,005	166,594	301,188
E	473	4,713	28,523	5,525	64,860	104,094
ESE	2,011	1,836	2,710	5,766	32,138	44,461
SE	231	6,085	1,057	1,662	5,065	14,100
SSE	277	1,358	1,197	7,992	1,537	12,361
S	567	1,015	14,426	3,223	5,073	24,304
SSW	267	980	2,214	6,037	6,848	16,346
SW	551	19,957	3,399	4,786	16,012	44,705
WSW	273	1,186	2,567	4,985	11,834	20,845
W	1,178	1,156	9,116	5,385	4,680	21,515
WNW	580	6,833	29,211	4,566	9,930	51,120
NW	2,876	17,610	1,704	10,150	5,104	37,444
NNW	9,612	1,863	4,912	3,630	4,705	24,722
Total	28,566	90,866	160,344	517,887	1,071,710	1,869,373

10 Population projection for 0-10 miles includes permanent residents, transients (including employees), seasonal residents, and special facilities. This population projection is based on year 2000 census data from SECPOP2000.

Table F.3-6
Projected Population Distribution Within a 10-Mile Radius of LSCS, Year 2043[11]

Sector	0-1 mile	1-2 miles	2-3 miles	3-4 miles	4-5 miles	5-10 miles	0-10 miles Total
N	0	1	28	0	1,934	1,493	3,456
NNE	0	0	0	208	646	2,297	3,151
NE	0	0	0	165	1,236	4,205	5,606
ENE	0	177	177	21	1	565	941
E	0	142	147	37	22	295	643
ESE	0	16	2,123	22	6	538	2,705
SE	0	4	6	17	31	262	320
SSE	0	4	10	25	11	326	376
S	0	7	22	20	9	691	749
SSW	0	0	20	7	21	308	356
SW	4	21	6	7	16	682	736
WSW	0	0	18	21	17	307	363
W	0	25	10	21	27	1,491	1,574
WNW	1	0	26	38	16	693	774
NW	0	15	3	52	400	3,371	3,841
NNW	1	0	40	4	218	12,570	12,833
Total	6	412	2,636	665	4,611	30,094	38,424

11 Population projection for 0-10 miles includes permanent residents, transients (including employees), seasonal residents, and special facilities. This population projection is based on year 2000 census data from SECPOP2000.

Table F.3-7
Projected Population Distribution within a 50-Mile Radius of LSCS, Year 2043[12]

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles	50-mile Total
N	3,456	7,000	26,360	11,702	87,562	136,080
NNE	3,151	1,894	21,448	225,910	401,416	653,819
NE	5,606	11,510	15,612	455,348	628,691	1,116,767
ENE	941	16,099	37,905	245,127	338,890	638,962
E	643	6,548	60,524	8,673	94,937	171,325
ESE	2,705	2,530	3,405	7,122	39,094	54,856
SE	320	7,524	1,243	1,934	6,009	17,030
SSE	376	1,598	1,400	9,351	1,789	14,514
S	749	1,187	16,880	4,018	6,748	29,582
SSW	356	1,155	2,610	7,722	9,231	21,074
SW	736	24,853	4,370	6,197	21,642	57,798
WSW	363	1,584	3,116	5,560	13,448	24,071
W	1,574	1,544	11,641	6,235	5,539	26,533
WNW	774	9,123	38,359	5,464	11,692	65,412
NW	3,841	23,511	2,276	12,250	5,627	47,505
NNW	12,833	2,488	6,652	4,789	5,807	32,569
Total	38,424	120,148	253,801	1,017,402	1,678,122	3,107,897

12 Population projection for 0-10 miles includes permanent residents, transients (including employees), seasonal residents, and special facilities. This population projection is based on year 2000 census data from SECPOP2000.

Table F.3-8
County Specific Land Use and Economic Parameters Inputs

County	Fraction Farm	Fraction Dairy	Farm Sales ($/hectare)	Farm Property Value ($/hectare)	Non-Farm Property Value ($/person)
Bureau	0.860	0.002	1,566	11,275	230,423
Cook	0.014	0.036	4,601	28,720	324,570
DeKalb	0.918	0.013	2,013	12,885	207,349
DuPage	0.038	0.000	4,374	20,877	385,139
Ford	0.871	0.002	1,331	11,055	250,120
Grundy	0.805	0.003	1,206	11,556	226,266
Iroquois	0.948	0.006	1,525	11,217	223,993
Kane	0.578	0.018	2,544	13,552	251,322
Kankakee	0.891	0.008	1,562	12,053	209,476
Kendall	0.814	0.008	1,532	12,032	227,743
LaSalle	0.886	0.001	1,263	11,680	223,468
Lee	0.852	0.002	1,338	11,992	210,685
Livingston	0.941	0.009	1,378	11,538	246,998
Marshall	0.828	0.005	1,215	11,262	241,404
McLean	0.893	0.053	1,339	11,633	254,519
Ogle	0.755	0.015	1,744	12,608	223,703
Peoria	0.654	0.013	1,203	10,798	275,390
Putnam	0.613	0.008	2,557	10,971	246,522
Tazewell	0.793	0.011	1,387	11,230	260,756
Will	0.412	0.013	1,427	15,683	260,590
Woodford	0.854	0.005	1,521	11,812	259,630

Table F.3-9
MACCS2 Economic Parameter Inputs

Variable	Description	Base Case Value
DPRATE[(1)]	Property depreciation rate (per yr)	0.20
DSRATE[(2)]	Investment rate of return (per yr)	0.07
EVACST[(3)]	Daily cost for a person who has been evacuated ($/person-day)	57.51
RELCST[(3)]	Daily cost for a person who is relocated ($/person-day)	57.51
POPCST[(3)]	Population relocation cost ($/person)	10,650
CDFRM0[(3)]	Cost of farm decontamination for two levels of decontamination ($/hectare)[(5)]	1,198 2,663
TIMDEC[(1)]	Decontamination time for each level[(5)]	2&4 months
CDNFRM[(3)]	Cost of non-farm decontamination per resident person for two levels of decontamination ($/person) [(5)]	6,390 17,040
DLBCST[(3)]	Average cost of decontamination labor ($/man-year)	74,550
TFWKF[(1)]	Time workers spend in farm land contaminated areas[(5)]	1/10 1/3
TFWKNF[(1)]	Time workers spend in non-farm land contaminated areas[(5)]	1/3 1/3
VALWF0[(4)]	Weighted average value of farm wealth ($/hectare)	11,937
VALWNF[(4)]	Weighted average value of non-farm wealth ($/person)	283,637

1 Uses NUREG/CR-4551 value (NRC 1990b).

2 DSRATE based on NUREG/BR-0058 (NRC 2004a).

3 These parameters use the NUREG/CR-4551 value (NRC 1990b), updated to July 2013 using the CPI.

4 VALWF0 and VALWNF are based on the 2007 Census of Agriculture (USDA 2009), Bureau of Labor Statistics (BLS 2013) and Bureau of Economic Analysis (BEA 2013) data, updated to July 2013 using the CPI for the counties within 50 miles.

5 Two decontamination levels are modeled. The first value is associated with a dose reduction factor of 3. The second value is associated with a dose reduction factor of 15.

Table F.3-10
COMIDA2 Related Input Parameter Values Used for the LSCS SAMA Analysis

PARAMETER	PARAMETER DESCRIPTION	VALUE EFFECTIVE (Rem)	VALUE THRYOID (Rem)
DOSEMILK	Maximum allowable food ingestion dose from milk crops during the year of the accident	0.25	2.5
DOSEOTHER	Maximum allowable food ingestion dose from non-milk crops during the year of the accident	0.25	2.5
DOSELONG	Maximum allowable long term annual dose to an individual from ingestion of the combination of milk and non-milk crops.	0.50	5.0

Table F.3-11
LSCS Core Inventory

Nuclide	Activity (Bq)	Nuclide	Activity (Bq)
Co-58	2.15E+16	Te-131m	5.02E+17
Co-60	2.36E+16	Te-132	4.94E+18
Kr-85	4.92E+16	I-131	3.48E+18
Kr-85m	1.07E+18	I-132	5.02E+18
Kr-87	2.10E+18	I-133	7.17E+18
Kr-88	2.97E+18	I-134	7.95E+18
Rb-86	8.27E+15	I-135	6.70E+18
Sr-89	3.59E+18	Xe-133	7.08E+18
Sr-90	3.94E+17	Xe-135	2.79E+18
Sr-91	4.90E+18	Cs-134	9.18E+17
Sr-92	5.18E+18	Cs-136	2.55E+17
Y-90	4.07E+17	Cs-137	5.71E+17
Y-91	4.43E+18	Ba-139	6.56E+18
Y-92	5.19E+18	Ba-140	6.32E+18
Y-93	5.84E+18	La-140	6.46E+18
Zr-95	5.76E+18	La-141	5.99E+18
Zr-97	6.01E+18	La-142	5.85E+18
Nb-95	5.79E+18	Ce-141	5.79E+18
Mo-99	6.55E+18	Ce-143	5.71E+18
Tc-99m	5.73E+18	Ce-144	4.61E+18
Ru-103	5.48E+18	Pr-143	5.54E+18
Ru-105	3.83E+18	Nd-147	2.37E+18
Ru-106	2.27E+18	Np-239	7.15E+19
Rh-105	3.61E+18	Pu-238	2.22E+16
Sb-127	3.80E+17	Pu-239	1.56E+15
Sb-129	1.13E+18	Pu-240	1.69E+15
Te-127	3.77E+17	Pu-241	8.08E+17
Te-127m	5.05E+16	Am-241	1.26E+15
Te-129	1.11E+18	Cm-242	2.92E+17
Te-129m	1.65E+17	Cm-244	3.33E+16

Table F.3-12
MACCS2 Radioisotope Groups vs. LSCS Level 2 Radioisotope Groups

MACCS2 Radioisotope Groups	LSCS Level 2 Radioisotope Groups[4]
Xe/Kr	1 – noble gases
I	2 – CsI
Cs	6 & 2 – CsOH and CsI[3]
Te	3, 10 & 11- TeO_2, Sb[2] & Te_2 [1]
Sr	4 – SrO
Ru	5 – MoO_2 (Mo is included in Ru MACCS category)
La	8 – La_2O_3
Ce	9 & 12 – CeO_2 & UO_2 [1]
Ba	7 – BaO

1 These release fractions are typically negligible compared to others in the group.

2 The mass of Sb in the core is typically much less than the mass of Te.

3 The mass of Cs contained in CsI is typically much less than the mass of Cs contained in CsOH.

4 The LSCS Level 2 radioisotope groups represent the twelve (12) MAAP 4.0.5 radioisotope groups.

Table F.3-13
LSCS Level 2 Source Term Category Summary

Release Category	Description
H/E	High/Early Release
H/I	High/Intermediate Release
H/L	High/Late Release
M/E	Moderate/Early Release
M/I	Moderate/Intermediate Release
M/L	Moderate/Late Release
L/E	Low/Early Release
L/I	Low/Intermediate Release
L/L	Low/Late Release
LL/E	Low-Low/Early Release
LL/I	Low-Low/Intermediate Release
LL/L	Low-Low/Late Release
OK	Containment OK

Table F.3-14
Level 2 End State Bins: Radionuclide Release
Severity and Timing Classification Scheme (Severity, Timing)(1)

Radionuclide Release Severity		Radionuclide Release Timing	
Classification Category	**Cs Iodide % in Release**	**Classification Category**	**Time of Initial Release(2) Relative to Declaration of a General Emergency**
High(4) (H)	Greater than 10%(4)	Late (L)	Greater than 24 hours
Moderate (M)	1% to 10%	Intermediate (I)	E(3) to 24 hours
Low (L)	Less than 1%	Early (E)	Less than E(3), (4) hours
No iodine (OK, Intact Containment)	negligible		

1 Thirteen (13) Level 2 End State Bins: H/E, H/I, H/L, M/E, M/I, M/L, L/E, L/I, L/L, LL/E, LL/I, LL/L, OK, Break Outside Containment (BOC-not shown but would be a H/E),

2 The General Emergency declaration is accident sequence dependent and occurs when EALs are exceeded.

3 Where E hours is less than the time when evacuation is effective (5 hours) for LSCS.

4 Consistent with NUREG/CR-6595 (NRC 1999).

Table F.3-15
Detailed Release Category Results

Endstate	LSCS Unit 2	
	Freq (/yr)	Percent
H/E-BOC	8.32E-08	3.2%
H/E	5.93E-08	2.3%
H/I	1.90E-08	0.7%
M/E	2.14E-07	8.3%
M/I	9.27E-07	35.9%
L/E	3.88E-07	15.0%
L/I	1.45E-07	5.6%
INTACT	7.45E-07	28.9%
Total	2.58E-06	100.0%

Table F.3-16
LSCS Release Category Bins

Release Category	Bin
High Magnitude / Early Release (Accident Class V, Unisolated LOCA Outside Containment)	H/E-BOC
High Magnitude / Early Release (non-BOC release)	H/E
High Magnitude / Intermediate Release High Magnitude / Late Release	H/I
Moderate Magnitude / Early Release	M/E
Moderate Magnitude / Intermediate Release Moderate Magnitude / Late Release	M/I
Low Magnitude / Early Release Low-low Magnitude / Early Release	L/E
Low Magnitude / Intermediate Release Low Magnitude / Late Release Low-low Magnitude / Intermediate Release Low-low Magnitude / Late Release	L/I
Containment Intact	CI

Table F.3-17
Release Bin MAAP Case Selection

Release Category Bin	MAAP Scenario Assigned	Accident Class	Release Fractions[13] CsI	CsOH	Assignment Rationale
H/E-BOC - High Magnitude / Early Release (Accident Class V, Unisolated LOCA Outside Containment)	LS130528	V	9.4E-1	8.7E-1	MAAP case LS130528 represents an H/E release following a Main Steam Line break outside of containment (Class V BOC frequency of 8.32E-08/yr). This MAAP case adequately represents an H/E release with an unisolated LOCA outside of containment (Class V accident). The break location in this MAAP run does not account for scrubbing from the secondary containment that would occur from the dominant break locations for this release category bin. Timing: The GE is assumed declared at 0.5 hours for a Class V accident due to a conservative 30 minute minimum window assumed for GE declaration. The RPV water level drops below -183" (MSCWLL) within a few minutes, which results in a loss of 2 fission barriers and a potential loss of the third barrier. Containment isolation fails at transient initiation, resulting in an early release.
H/E – High/Early Release	LS130521x	IIID	2.6E-1	2.1E-1	The H/E bin (5.93E-8/yr) represents non-BOC H/E sequences and is dominated by Class IIID (45% of the H/E frequency) and Class IV (ATWS) sequences (31% of H/E frequency). The non-BOC H/E frequency evolves primarily from sequences IIID-009 (45% of the H/E frequency) and IV-041 (23% of H/E frequency). Sequence IIID-009 represents a LOCA event with

[13] Radionuclide release fraction to the environment of CsOH (Cesium Hydroxide, FREL(6)) and CsI (Cesium Iodine, FREL(2)) quoted at the end of the MAAP run.

Table F.3-17
Release Bin MAAP Case Selection

Release Category Bin	MAAP Scenario Assigned	Accident Class	Release Fractions[13] CsI	CsOH	Assignment Rationale
					successful RPV depressurization but without successful make-up that leads to containment failure prior to RPV failure. Sequence IV-041 represents an ATWS scenario with successful RPV depressurization and an RPV failure followed by a wetwell water space failure. The Level 2 reference MAAP case for sequence IIID-009 is LS130521x (CsI release fraction (RF) of 2.6E-1). The representative MAAP case for sequence IV-041 is LS130523 (CsI RF of 1.1E-1). Case LS130521x is chosen as the representative case since the IIID-009 sequence dominates the non-BOC H/E frequency and has a CsI RF more representative of an H/E release. <u>Timing</u>: The GE is assumed declared at 0.5 hours for a Class V accident due to a conservative 30 minute minimum window assumed for GE declaration. The RPV water level drops below -183” within a few minutes, which results in a loss of 2 fission barriers and a potential loss of the third barrier. Containment fails at transient initiation due to failure to isolate containment.
H/I - High/Intermediate Release	LS130536x	IBL	4.9E-1	3.0E-1	The H/I bin (1.90E-08/yr) is driven by IBL (85% of the H/I frequency) sequences. The dominant sequence leading to the H/I end state is the IBL-081 sequence (74% of the H/I frequency). The IBL-081 sequence is characterized by a station blackout scenario with unsuccessful RPV depressurization without injection to containment available. Sequence IBL-081 results in

Table F.3-17
Release Bin MAAP Case Selection

Release Category Bin	MAAP Scenario Assigned	Accident Class	Release Fractions[13] CsI	CsOH	Assignment Rationale
					the failure of the drywell due to overpressure. The reference MAAP case for the IBL-081 sequence is LS130536x (CsI RF of 4.9E-1). Case LS130536x is chosen as the representative MAAP case since it represents the most dominant sequence of the release bin. Timing: The GE would be declared at approximately 5.6 hours for the selected MAAP case due to the RPV level rapidly dropping below MSCWLL at that time. Once the level drops below MSCWLL, two fission barriers are lost along with the potential loss of the third barrier. The failure of containment is at 11.1 hours, which is greater than 4 hours and less than 24 hours after the GE is declared.
H/L - High/Late Release	N/A	N/A	N/A	N/A	The H/L bin release frequency was calculated as negligible in the LSCS Level 2 PRA model. This group is subsumed by the H/I end state.
M/E - Moderate/Early Release	LS130524	IV	7.1E-2	8.0E-2	The M/E bin (2.14E-07/yr) is dominated by the Class IV sequences (83% of the M/E frequency). The dominant sequence, IV-014 (68% of the M/E frequency), represents an ATWS scenario with a successful RPV depressurization and RPV failure prior to a wetwell airspace failure. The reference MAAP case for sequence IV-014 is LS130524 (CsI RF of 7.1E-2) LS130524 models a scenario with a wetwell airspace failure prior to RPV failure. However, the dominate sequences represent scenarios with wetwell airspace failure following RPV

Table F.3-17
Release Bin MAAP Case Selection

Release Category Bin	MAAP Scenario Assigned	Accident Class	Release Fractions[13] CsI	CsOH	Assignment Rationale
					failure. The MAAP case is judged adequate to represent the sequences since the impact of a wetwell airspace failure prior to RPV failure has a relatively minor impact on the release fractions. MAAP case LS130524 is chosen as the representative MAAP case since it represents the most dominant sequence (sequence IV-014). Timing: The GE is assumed declared at 0.5 hours for a Class IV accident due to a conservative 30 minute minimum window assumed for GE declaration. The RPV water level drops below -183” within a few minutes, which results in a loss of 2 fission barriers and a potential loss of the third barrier. The containment failure time is 1.7 hours after accident initiation.
M/I - Moderate/ Intermediate Release	LS130516	II	2.9E-2	9.0E-2	The M/I bin (9.27E-07/yr) is dominated by Class II sequences (86% of the M/I frequency). Sequence II-067 (35% of the M/I frequency) represents a loss of decay heat removal scenario with successful RPV depressurization and a failure of the drywell due to drywell overpressure following RPV failure. Sequence II-014 (29% of the M/I frequency) represents a loss of decay heat removal scenario with successful RPV depressurization and a wetwell airspace failure following RPV failure. The representative MAAP case for sequence II-067 is LS130516 (CsI RF of 2.9E-2). The reference MAAP case for sequences II-014 is LS130514 (CsI RF of 9.7E-3).

Table F.3-17
Release Bin MAAP Case Selection

Release Category Bin	MAAP Scenario Assigned	Accident Class	Release Fractions[13] CsI	CsOH	Assignment Rationale
					Case LS130516 is chosen as the representative MAAP case since it represents the most dominant sequence (sequence II-067). Timing: For Class II sequences the GE is assumed to be declared in the "early" time frame. The GE is assumed to be declared at t=4hrs. The selected MAAP case results in a containment failure at 27.6 hours followed by core damage time of 28.3, greater than 4 and less than 24 hours after the GE is declared.
M/L - Moderate/Late Release	N/A	N/A	N/A	N/A	The M/L bin release frequency was calculated as negligible in the LSCS Level 2 PRA model. This group is subsumed by the M/I end state.
L/E - Low/Early Release	LS130533B	IA	1.1E-3	2.4E-4	The L/E release frequency (3.88E-07/yr) is dominated by the Class IV (75% of the L/E frequency) sequence. Sequence IV-004 (75% of the L/E frequency) represents an ATWS scenario with successful RPV depressurization, arrested core melt in-vessel, and a wetwell airspace failure without suppression pool bypass. The reference MAAP case for sequence IV-004 is case LS130524 (CsI RF of 7.1E-2). However, case LS130524 does not model the core melt arresting in-vessel. If the core melt is arrested in-vessel, the release magnitude would be lower. It should be noted that the reference MAAP cases in the Level 2 analysis are not necessarily exact models of the sequence, but are instead used along with the Level 2 Release Category rules to assign

Table F.3-17
Release Bin MAAP Case Selection

Release Category Bin	MAAP Scenario Assigned	Accident Class	Release Fractions[13] CsI	CsOH	Assignment Rationale
					an appropriate end state to the Level 2 sequence. MAAP case LS130533B (CsI RF of 1.1E-3) represents a loss of RPV injection sequence ending with containment flooding and venting and is judged to adequately represent the L/E release category bin. Timing: The GE is assumed declared at 0.5 hours for a Class IA accident due to a conservative 30 minute minimum window assumed for GE declaration. The RPV water level reaches -183" in that time frame, which results in the loss of 2 fission barriers with a potential loss of the third barrier. The selected MAAP case reaches core damage at 48 minutes followed by successful containment venting at 4.6 hours after accident initiation.
L/I - Low/Intermediate Release	LS130534	ID	4.3E-3	3.5E-3	The L/I bin (1.45E-07/yr) is dominated by the Class IBL (57% of the L/I frequency), and IIV (18% of the L/I frequency) sequences. The dominant sequences are IBL-004 (21% of the L/I frequency) and IIV-004 (18% of the L/I frequency. Sequence IBL-004 represents a station blackout scenario with successful RPV depressurization, arrested core melt in-vessel, and successful containment flooding and venting. Sequence IIV-004 represents a station blackout scenario with successful RPV depressurization, arrested core melt in-vessel, and a wetwell airspace failure without suppression pool bypass. The reference MAAP case for sequence IBL-004 is LS130534 (CsI RF of 5.2E-3). This case models loss of injection, successful depressurization, and

Table F.3-17
Release Bin MAAP Case Selection

Release Category Bin	MAAP Scenario Assigned	Accident Class	Release Fractions[13] CsI	CsOH	Assignment Rationale
					successful containment venting and flooding. However, case LS130534 does not model the core melt arresting in-vessel. If the core melt is arrested in-vessel, the release magnitude would be lower. It should be noted that the reference MAAP cases in the Level 2 analysis are not necessarily exact models of the sequence, but are instead used along with the Level 2 Release Category rules to assign an appropriate end state to the Level 2 sequence. The representative MAAP case for scenario IIV-004 is LS130537 (CsI RF of 2.1E-1). MAAP case LS130534 is chosen as the representative case for this bin since it represents the most dominant sequence (LS130534) and is adequately representative of the L/I category. <u>Timing:</u> The GE is assumed declared at 0.5 hours due to a conservative 30 minute minimum window assumed for GE declaration. The RPV water level would reach -183” in that time frame, which results in the loss of 2 fission barriers with a potential loss of the third barrier. The selected MAAP case reaches core damage at 36 minutes followed by successful containment venting at t=5.3 hrs.
L/L - Low/Late Release	N/A	N/A	N/A	N/A	The L/L bin release frequency was calculated as negligible in the LSCS Level 2 PRA model. This group is subsumed by the L/I end state.
LL/E - Low-Low/Early Release	N/A	N/A	N/A	N/A	The LL/E bin release frequency was calculated as negligible in the LSCS Level 2 PRA model. This group is subsumed by the L/E end state.

Table F.3-17
Release Bin MAAP Case Selection

Release Category Bin	MAAP Scenario Assigned	Accident Class	Release Fractions[13] CsI	CsOH	Assignment Rationale
LL/I - Low-Low/Intermediate Release	N/A	N/A	N/A	N/A	The LL/I bin release frequency was calculated as negligible in the LSCS Level 2 PRA model. This group is subsumed by the L/I end state.
LL/L - Low-Low/Late Release	N/A	N/A	N/A	N/A	The LL/L bin release frequency was calculated as negligible in the LSCS Level 2 PRA model. This group is subsumed by the L/L end state.
CI – Containment Intact	LS130531	OK	8.5E-6	3.9E-6	MAAP case LS130531 is chosen as the MAAP case to represent Tech Spec leakage out of an intact containment (7.45E-07/yr) with no RPV depressurization. This case is chosen over the MAAP case simulating a Tech Spec leakage with successful RPV depressurization (LS130532) as the case with no RPV depressurization has a higher CsI release fraction. Timing: The GE would be declared at 0.5 hours for the selected MAAP case due to the RPV water level reaching -183” in that time frame, which results in the loss of 2 fission barriers with a potential loss of the third barrier. For the selected MAAP case, core damage occurs in 48 minutes with no containment failure.

Table F.3-18
LSCS MAAP 4.0.5 Level 2 Runs to Support SAMA

Case	Description	TAF	ED	MSCWLL (GE)(2)	CD	Vessel Breach	Cont. Failure(1)	NG(1) Release Fraction	CsI (CsOH)(1),(3) Release Fraction	Release Category	Run Time	Comments
LS130528	BOC LLOCA No Injection No ED No SPC or sprays	<1 min	N/A	< 1 min (30 min)	14 min	4.2 hr	N/A BOC on MSL (26" dia.)	1.0	9.4E-1 (8.7E-1)	HE - BOC	40 hr.	Break Outside Containment (26" break on MSL) with no Isolation
LS130521x	Containment Isolation Unsuccessful ($2ft^2$) LLOCA (Water) No Injection No SRVs No SPC or sprays	<1 min	N/A	<1 min (30 min)	7 min	3.2 hr	N/A Containment Isolation Unsuccessful ($2ft^2$)	1.0	2.6E-1 (2.1E-1)	HE	40 hr.	Lower pedestal walls fail when corium sideward erosion distance exceeds thickness of lower pedestal wall at t=16.3 hrs.
LS130536x	SBO DW Head Failure ($2ft^2$) MSIV Closure RCIC for 4 hrs. No SRVs No SPC or Sprays	5.5 hr	N/A	5.6 hr (5.6 hr)	6.4 hr	9.9 hr	11.1 hr	1.0	4.9E-1 (3.0E-1)	HI	48 hr.	Lower pedestal walls fail when corium sideward erosion distance exceeds thickness of lower pedestal wall at t=30 hrs.

Table F.3-18
LSCS MAAP 4.0.5 Level 2 Runs to Support SAMA

Case	Description	TAF	ED	MSCWLL (GE)(2)	CD	Vessel Breach	Cont. Failure(1)	NG(1) Release Fraction	CsI (CsOH)(1),(3) Release Fraction	Release Category	Run Time	Comments
LS130524	WWA Failure ($2ft^2$) ATWS with no SBLC FW, RCIC,LPCI 3 SRVs at -150" No SPC or sprays	6 min	3 SRVs @ 5 min	6 min (30 min)	2.0 hr	6.7 hr	1.7 hr	1.0	7.1E-2 (8.0E-2)	ME	100 hr.	
LS130516	DW head Failure ($2ft^2$) MSIV Closure LPCS 2 SRVs at -150" No SPC or sprays	18 min	2 SRVs @ 17 min	27.1 hr (4.0 hr)(4)	28.3	35.5 hr	27.6 hr	1.0	2.9E-2 (9.0E-2)	MI	100 hr.	
LS130533B	Containment Vent (uncontrolled) Containment Flood MSIV closure No injection No SRVs COND to RPV available at vessel failure	20 min	N/A	25 min (30 min)	48 min	3.2 hr	N/A Containment vented at 60 psig @ 4.6 hr (8" Containment vent)	1.0	1.1E-3 (2.3E-4)	LE	40 hr.	Containment vent at PCPL of 60 psig and left open. Drywell flooded via condensate (3000gpm) through RPV breach. Flooding begins at RPV breach.

Table F.3-18
LSCS MAAP 4.0.5 Level 2 Runs to Support SAMA

Case	Description	TAF	ED	MSCWLL (GE)[(2)]	CD	Vessel Breach	Cont. Failure[(1)]	NG[(1)] Release Fraction	CsI (CsOH)[(1),(3)] Release Fraction	Release Category	Run Time	Comments
LS130534	Containment Vent (controlled) Containment Flood MSIV closure No injection 2 SRVs at -150" FP to RPV available at vessel failure	19 min	2 SRVs @ 18 min	19 min (30 min)	36 min	4.3 hr	N/A Containment vented and cycled at 60 psig initially @ 5.3 hr (8" Containment vent)	1.0	5.2E-3 (3.8E-3)	LI	80 hr.	Containment vent at PCPL of 60 psig and controlled between 50-60 psig. Drywell flooded via FP through RPV breach. Flooding begins at RPV breach.
LS130531	Containment Intact MSIV closure No injection No SRVs 1 Loop of SPC 1 loop of sprays w/ Hx	20 min	N/A	25 min (30 min)	48 min	3.2 hr	N/A Containment Intact	1.9E-2	8.5E-6 (3.9E-6)	INTACT	60 hr.	Demonstrates no containment failure with sprays and SPC available with RHR HX.

1 Prior to containment failure, a 0.5% drywell gas volume per day leakage is assumed in each of the calculations. This leakage impacts the calculated release fractions of fission products.

2 The General Emergency (GE) declaration is accident sequence dependent and occurs when EALs are exceeded. For LSCS Units 1 and 2, the site would be expected to declare a general emergency if the RPV water level cannot be restored above -183", or when MSCWLL is indicated to the operators. If MAAP 4.0.5 calculates that the PRV water level drops below MSCWLL following an RPV depressurization with adequate injection available to increase the water level above MSCWLL shortly following (e.g., <15 minutes) the depressurization, the EALs are assumed to not be exceeded. The earliest time a GE can be declared is conservatively assumed to be 30 minutes. The GE for each scenario will either be 30 minutes if the time to MSCWLL is shorter than 30 minutes or will be equal to the time to MSCWLL is the time to MSCWLL is greater than 30 minutes.

3 The reported release fractions are based on the release fractions for CsI and CsOH at the end of the MAAP run.

4 General Emergency time determined probabilistically.

Table F.3-19
LSCS SOURCE TERM RELEASE SUMMARY

	Release Category							
	H/E-BOC	**H/E**	**H/I**	**M/E**	**M/I**	**L/E**	**L/I**	**INTACT**
MAAP Case	LS130528	LS130521X	LS130536X	LS130524	LS130516	LS130524B	LS130534	LS130531
Run Duration (hours)(1)	40 hr	40 hr	48 hr	100 hr	100 hr	40 hr	80 hr	60 hr
Time (hours) after Scram when GE is declared (2)	0.50	0.50	5.60	0.50	4.00	0.50	0.50	0.50
Fission Product Group:								
1) Noble								
Total Release Fraction	1.00E+00	1.00E+00	1.00E+00	1.00E+00	1.00E+00	1.00E+00	1.00E+00	3.06E-02
Total Plume 1 Release Fraction	1.00E+0	8.16E-1	1.00E+0	1.00E+0	1.00E+0	9.40E-1	5.37E-1	1.18E-3
Start of Plume 1 Release (hr)	0.25	0.00	11.00	2.00	27.50	1.50	5.25	1.00
End of Plume 1 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
Total Plume 2 Release Fraction	0.00E+0	1.65E-1	0.00E+0	0.00E+0	0.00E+0	3.80E-2	4.62E-1	3.09E-3
Start of Plume 2 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
End of Plume 2 Release (hr)	10.00	5.25	18.00	20.00	47.50	4.50	12.50	10.00
Total Plume 3 Release Fraction	0.00E+0	1.90E-2	0.00E+0	0.00E+0	0.00E+0	2.20E-2	1.00E-3	2.63E-2
Start of Plume 3 Release (hr)	10.00	5.25	18.00	20.00	57.50	4.50	12.50	10.00
End of Plume 3 Release (hr)	20.00	15.25	28.00	30.00	67.50	14.50	22.50	20.00
2) CsI								
Total Release Fraction	9.37E-01	2.56E-01	4.92E-01	7.15E-02	2.95E-02	1.19E-03	5.19E-03	8.53E-06
Total Plume 1 Release Fraction	8.72E-1	1.93E-1	4.15E-1	8.48E-3	1.28E-2	8.88E-4	2.44E-3	7.50E-6
Start of Plume 1 Release (hr)	0.25	0.00	11.00	2.00	27.50	1.50	5.25	1.00

Table F.3-19
LSCS SOURCE TERM RELEASE SUMMARY

	Release Category							
	H/E-BOC	**H/E**	**H/I**	**M/E**	**M/I**	**L/E**	**L/I**	**INTACT**
MAAP Case	LS130528	LS130521X	LS130536X	LS130524	LS130516	LS130524B	LS130534	LS130531
Run Duration (hours)(1)	40 hr	40 hr	48 hr	100 hr	100 hr	40 hr	80 hr	60 hr
Time (hours) after Scram when GE is declared (2)	0.50	0.50	5.60	0.50	4.00	0.50	0.50	0.50
Fission Product Group:								
End of Plume 1 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
Total Plume 2 Release Fraction	5.80E-2	5.00E-2	5.60E-2	2.31E-2	1.34E-2	2.80E-4	2.50E-3	8.90E-7
Start of Plume 2 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
End of Plume 2 Release (hr)	10.00	5.25	18.00	20.00	47.50	4.50	12.50	10.00
Total Plume 3 Release Fraction	7.00E-3	1.30E-2	2.10E-2	3.99E-2	3.30E-3	2.00E-5	2.50E-4	1.40E-7
Start of Plume 3 Release (hr)	10.00	5.25	18.00	20.00	57.50	4.50	12.50	10.00
End of Plume 3 Release (hr)	20.00	15.25	28.00	30.00	67.50	14.50	22.50	20.00
3) TeO2								
Total Release Fraction	7.51E-01	2.24E-01	2.77E-01	6.88E-02	5.05E-02	1.01E-03	8.95E-04	4.94E-06
Total Plume 1 Release Fraction	6.85E-1	1.59E-1	1.56E-1	8.55E-3	2.09E-3	9.23E-4	5.75E-4	3.26E-6
Start of Plume 1 Release (hr)	0.25	0.00	11.00	2.00	27.50	1.50	5.25	1.00
End of Plume 1 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
Total Plume 2 Release Fraction	4.00E-2	9.00E-3	1.19E-1	5.54E-2	1.17E-2	8.00E-5	3.12E-4	1.60E-6
Start of Plume 2 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
End of Plume 2 Release (hr)	10.00	5.25	18.00	20.00	47.50	4.50	12.50	10.00
Total Plume 3 Release Fraction	2.60E-2	5.60E-2	2.00E-3	4.80E-3	3.67E-2	1.00E-5	8.00E-6	8.00E-8

Table F.3-19
LSCS SOURCE TERM RELEASE SUMMARY

	Release Category							
	H/E-BOC	**H/E**	**H/I**	**M/E**	**M/I**	**L/E**	**L/I**	**INTACT**
MAAP Case	LS130528	LS130521X	LS130536X	LS130524	LS130516	LS130524B	LS130534	LS130531
Run Duration (hours)(1)	40 hr	40 hr	48 hr	100 hr	100 hr	40 hr	80 hr	60 hr
Time (hours) after Scram when GE is declared (2)	0.50	0.50	5.60	0.50	4.00	0.50	0.50	0.50
Fission Product Group:								
Start of Plume 3 Release (hr)	10.00	5.25	18.00	20.00	57.50	4.50	12.50	10.00
End of Plume 3 Release (hr)	20.00	15.25	28.00	30.00	67.50	14.50	22.50	20.00
4) SrO								
Total Release Fraction	4.65E-02	5.97E-03	1.07E-02	2.46E-02	7.37E-03	8.35E-06	1.75E-04	6.50E-11
Total Plume 1 Release Fraction	1.07E-02	1.91E-3	5.19E-3	2.46E-2	3.16E-4	7.56E-6	1.59E-4	6.50E-11
Start of Plume 1 Release (hr)	0.25	0.00	11.00	2.00	27.50	1.50	5.25	1.00
End of Plume 1 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
Total Plume 2 Release Fraction	3.58E-02	2.56E-3	5.50E-3	0.00E+0	7.05E-3	6.50E-7	1.60E-5	0.00E+0
Start of Plume 2 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
End of Plume 2 Release (hr)	10.00	5.25	18.00	20.00	47.50	4.50	12.50	10.00
Total Plume 3 Release Fraction	0.00	1.50E-3	0.00E+0	0.00E+0	0.00E+0	1.40E-7	0.00E+0	0.00E+0
Start of Plume 3 Release (hr)	10.00	5.25	18.00	20.00	57.50	4.50	12.50	10.00
End of Plume 3 Release (hr)	20.00	15.25	28.00	30.00	67.50	14.50	22.50	20.00
5) MoO2								
Total Release Fraction	4.15E-02	1.16E-02	5.18E-06	3.35E-05	2.64E-05	2.69E-05	4.18E-09	6.97E-10
Total Plume 1 Release Fraction	4.15E-2	1.16E-2	3.33E-6	2.71E-5	2.44E-5	2.15E-5	3.95E-9	6.97E-10

Table F.3-19
LSCS SOURCE TERM RELEASE SUMMARY

	Release Category							
	H/E-BOC	**H/E**	**H/I**	**M/E**	**M/I**	**L/E**	**L/I**	**INTACT**
MAAP Case	LS130528	LS130521X	LS130536X	LS130524	LS130516	LS130524B	LS130534	LS130531
Run Duration (hours)[(1)]	40 hr	40 hr	48 hr	100 hr	100 hr	40 hr	80 hr	60 hr
Time (hours) after Scram when GE is declared [(2)]	0.50	0.50	5.60	0.50	4.00	0.50	0.50	0.50
Fission Product Group:								
Start of Plume 1 Release (hr)	0.25	0.00	11.00	2.00	27.50	1.50	5.25	1.00
End of Plume 1 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
Total Plume 2 Release Fraction	0.00E+0	0.00E+0	1.00E-7	6.30E-6	1.90E-6	4.10E-6	2.30E-10	0.00E+0
Start of Plume 2 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
End of Plume 2 Release (hr)	10.00	5.25	18.00	20.00	47.50	4.50	12.50	10.00
Total Plume 3 Release Fraction	0.00E+0	0.00E+0	1.75E-6	1.00E-7	1.00E-7	1.30E-6	0.00E+0	0.00E+0
Start of Plume 3 Release (hr)	10.00	5.25	18.00	20.00	57.50	4.50	12.50	10.00
End of Plume 3 Release (hr)	20.00	15.25	28.00	30.00	67.50	14.50	22.50	20.00
6) CsOH								
Total Release Fraction	8.66E-01	2.06E-01	3.02E-01	7.98E-02	8.98E-02	9.48E-04	3.81E-03	3.94E-06
Total Plume 1 Release Fraction	6.85E-1	1.30E-1	1.08E-1	1.20E-2	9.64E-3	8.88E-4	1.53E-3	1.79E-6
Start of Plume 1 Release (hr)	0.25	0.00	11.00	2.00	27.50	1.50	5.25	1.00
End of Plume 1 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
Total Plume 2 Release Fraction	1.00E-1	1.50E-2	1.86E-1	5.95E-2	3.06E-2	4.90E-5	2.05E-3	1.71E-6
Start of Plume 2 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00

Table F.3-19
LSCS SOURCE TERM RELEASE SUMMARY

	Release Category							
	H/E-BOC	**H/E**	**H/I**	**M/E**	**M/I**	**L/E**	**L/I**	**INTACT**
MAAP Case	LS130528	LS130521X	LS130536X	LS130524	LS130516	LS130524B	LS130534	LS130531
Run Duration (hours)(1)	40 hr	40 hr	48 hr	100 hr	100 hr	40 hr	80 hr	60 hr
Time (hours) after Scram when GE is declared (2)	0.50	0.50	5.60	0.50	4.00	0.50	0.50	0.50
Fission Product Group:								
End of Plume 2 Release (hr)	10.00	5.25	18.00	20.00	47.50	4.50	12.50	10.00
Total Plume 3 Release Fraction	8.10E-2	6.10E-2	8.00E-3	8.30E-3	4.96E-2	1.10E-5	2.30E-4	4.40E-7
Start of Plume 3 Release (hr)	10.00	5.25	18.00	20.00	57.50	4.50	12.50	10.00
End of Plume 3 Release (hr)	20.00	15.25	28.00	30.00	67.50	14.50	22.50	20.00
7) BaO								
Total Release Fraction	6.22E-02	1.49E-02	4.74E-03	1.08E-02	3.28E-03	5.12E-05	7.73E-05	2.26E-10
Total Plume 1 Release Fraction	4.74E-2	1.31E-2	2.27E-3	1.07E-2	2.00E-4	4.44E-5	6.97E-5	2.26E-10
Start of Plume 1 Release (hr)	0.25	0.00	11.00	2.00	27.50	1.50	5.25	1.00
End of Plume 1 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
Total Plume 2 Release Fraction	1.48E-2	1.10E-3	2.46E-3	1.00E-4	3.08E-3	5.40E-6	7.60E-6	0.00E+0
Start of Plume 2 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
End of Plume 2 Release (hr)	10.00	5.25	18.00	20.00	47.50	4.50	12.50	10.00
Total Plume 3 Release Fraction	0.00E+0	7.00E-4	1.00E-5	0.00E+0	0.00E+0	1.40E-6	0.00E+0	0.00E+0
Start of Plume 3 Release (hr)	10.00	5.25	18.00	20.00	57.50	4.50	12.50	10.00
End of Plume 3 Release (hr)	20.00	15.25	28.00	30.00	67.50	14.50	22.50	20.00

Table F.3-19
LSCS SOURCE TERM RELEASE SUMMARY

	Release Category							
	H/E-BOC	**H/E**	**H/I**	**M/E**	**M/I**	**L/E**	**L/I**	**INTACT**
MAAP Case	LS130528	LS130521X	LS130536X	LS130524	LS130516	LS130524B	LS130534	LS130531
Run Duration (hours)[(1)]	40 hr	40 hr	48 hr	100 hr	100 hr	40 hr	80 hr	60 hr
Time (hours) after Scram when GE is declared [(2)]	0.50	0.50	5.60	0.50	4.00	0.50	0.50	0.50
Fission Product Group:								
8) La2O3								
Total Release Fraction	4.97E-03	4.52E-04	3.59E-04	2.48E-03	2.06E-04	5.90E-07	1.37E-05	6.26E-12
Total Plume 1 Release Fraction	4.48E-4	1.48E-4	1.25E-4	2.48E-3	2.92E-6	4.10E-7	1.20E-5	6.26E-12
Start of Plume 1 Release (hr)	0.25	0.00	11.00	2.00	27.50	1.50	5.25	1.00
End of Plume 1 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
Total Plume 2 Release Fraction	4.52E-3	1.62E-4	2.34E-4	0.00E+0	2.03E-4	1.58E-7	1.70E-6	0.00E+0
Start of Plume 2 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
End of Plume 2 Release (hr)	10.00	5.25	18.00	20.00	47.50	4.50	12.50	10.00
Total Plume 3 Release Fraction	0.00E+0	1.42E-4	0.00E+0	0.00E+0	0.00E+0	2.20E-8	0.00E+0	0.00E+0
Start of Plume 3 Release (hr)	10.00	5.25	18.00	20.00	57.50	4.50	12.50	10.00
End of Plume 3 Release (hr)	20.00	15.25	28.00	30.00	67.50	14.50	22.50	20.00
9) CeO2								
Total Release Fraction	4.10E-02	5.15E-03	7.40E-03	3.24E-02	5.07E-03	8.32E-07	3.21E-04	3.10E-11
Total Plume 1 Release Fraction	6.02E-4	1.62E-4	2.35E-3	3.22E-2	7.20E-5	6.08E-7	2.79E-4	3.10E-11
Start of Plume 1 Release (hr)	0.25	0.00	11.00	2.00	27.50	1.50	5.25	1.00

Table F.3-19
LSCS SOURCE TERM RELEASE SUMMARY

	Release Category							
	H/E-BOC	**H/E**	**H/I**	**M/E**	**M/I**	**L/E**	**L/I**	**INTACT**
MAAP Case	LS130528	LS130521X	LS130536X	LS130524	LS130516	LS130524B	LS130534	LS130531
Run Duration (hours)(1)	40 hr	40 hr	48 hr	100 hr	100 hr	40 hr	80 hr	60 hr
Time (hours) after Scram when GE is declared (2)	0.50	0.50	5.60	0.50	4.00	0.50	0.50	0.50
Fission Product Group:								
End of Plume 1 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
Total Plume 2 Release Fraction	4.04E-2	2.06E-3	5.05E-3	2.00E-4	5.00E-3	2.01E-7	4.20E-5	0.00E+0
Start of Plume 2 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
End of Plume 2 Release (hr)	10.00	5.25	18.00	20.00	47.50	4.50	12.50	10.00
Total Plume 3 Release Fraction	0.00E+0	2.93E-3	0.00E+0	0.00E+0	0.00E+0	2.30E-8	0.00E+0	0.00E+0
Start of Plume 3 Release (hr)	10.00	5.25	18.00	20.00	57.50	4.50	12.50	10.00
End of Plume 3 Release (hr)	20.00	15.25	28.00	30.00	67.50	14.50	22.50	20.00
10) Sb								
Total Release Fraction	7.88E-01	4.83E-01	2.57E-01	1.24E-01	1.07E-01	4.12E-03	1.86E-03	4.69E-07
Total Plume 1 Release Fraction	6.72E-01	1.60E-01	4.08E-02	5.52E-02	2.20E-02	3.74E-03	1.03E-03	2.55E-07
Start of Plume 1 Release (hr)	0.25	0.00	11.00	2.00	27.50	1.50	5.25	1.00
End of Plume 1 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
Total Plume 2 Release Fraction	1.02E-01	2.20E-02	9.70E-02	5.30E-02	6.13E-02	8.00E-05	6.80E-04	1.83E-07
Start of Plume 2 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
End of Plume 2 Release (hr)	10.00	5.25	18.00	20.00	47.50	4.50	12.50	10.00

Table F.3-19
LSCS SOURCE TERM RELEASE SUMMARY

	Release Category							
	H/E-BOC	**H/E**	**H/I**	**M/E**	**M/I**	**L/E**	**L/I**	**INTACT**
MAAP Case	LS130528	LS130521X	LS130536X	LS130524	LS130516	LS130524B	LS130534	LS130531
Run Duration (hours)(1)	40 hr	40 hr	48 hr	100 hr	100 hr	40 hr	80 hr	60 hr
Time (hours) after Scram when GE is declared (2)	0.50	0.50	5.60	0.50	4.00	0.50	0.50	0.50
Fission Product Group:								
Total Plume 3 Release Fraction	1.40E-02	3.01E-01	1.19E-01	1.60E-02	2.40E-02	3.00E-04	1.50E-04	3.10E-08
Start of Plume 3 Release (hr)	10.00	5.25	18.00	20.00	57.50	4.50	12.50	10.00
End of Plume 3 Release (hr)	20.00	15.25	28.00	30.00	67.50	14.50	22.50	20.00
11) Te2								
Total Release Fraction	8.00E-04	1.01E-03	7.61E-03	4.30E-04	1.46E-03	0.00E+00	3.51E-05	6.88E-11
Total Plume 1 Release Fraction	0.00E+00	0.00E+00	6.90E-03	3.21E-04	1.78E-04	0.00E+00	2.61E-05	6.79E-11
Start of Plume 1 Release (hr)	0.25	0.00	11.00	2.00	27.50	1.50	5.25	1.00
End of Plume 1 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
Total Plume 2 Release Fraction	7.98E-04	5.52E-04	3.90E-04	1.00E-06	1.20E-03	0.00E+00	4.50E-06	5.00E-13
Start of Plume 2 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
End of Plume 2 Release (hr)	10.00	5.25	18.00	20.00	47.50	4.50	12.50	10.00
Total Plume 3 Release Fraction	2.00E-06	4.60E-04	3.20E-04	1.08E-04	8.00E-05	0.00E+00	4.50E-06	4.00E-13
Start of Plume 3 Release (hr)	10.00	5.25	18.00	20.00	57.50	4.50	12.50	10.00
End of Plume 3 Release (hr)	20.00	15.25	28.00	30.00	67.50	14.50	22.50	20.00
12) UO2								
Total Release Fraction	2.63E-04	3.02E-05	3.05E-05	1.87E-04	2.32E-05	0.00E+00	9.48E-07	2.86E-14

Table F.3-19
LSCS SOURCE TERM RELEASE SUMMARY

	Release Category							
	H/E-BOC	**H/E**	**H/I**	**M/E**	**M/I**	**L/E**	**L/I**	**INTACT**
MAAP Case	LS130528	LS130521X	LS130536X	LS130524	LS130516	LS130524B	LS130534	LS130531
Run Duration (hours)(1)	40 hr	40 hr	48 hr	100 hr	100 hr	40 hr	80 hr	60 hr
Time (hours) after Scram when GE is declared (2)	0.50	0.50	5.60	0.50	4.00	0.50	0.50	0.50
Fission Product Group:								
Total Plume 1 Release Fraction	0.00E+00	0.00E+00	7.68E-06	1.60E-04	1.69E-07	0.00E+00	7.90E-07	2.86E-14
Start of Plume 1 Release (hr)	0.25	0.00	11.00	2.00	27.50	1.50	5.25	1.00
End of Plume 1 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
Total Plume 2 Release Fraction	2.61E-04	9.43E-06	2.11E-05	2.70E-05	2.30E-05	0.00E+00	1.58E-07	0.00E+00
Start of Plume 2 Release (hr)	3.25	1.75	12.00	10.00	37.50	3.50	6.50	5.00
End of Plume 2 Release (hr)	10.00	5.25	18.00	20.00	47.50	4.50	12.50	10.00
Total Plume 3 Release Fraction	2.00E-06	2.08E-05	1.70E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)	10.00	5.25	18.00	20.00	57.50	4.50	12.50	10.00
End of Plume 3 Release (hr)	20.00	15.25	28.00	30.00	67.50	14.50	22.50	20.00

1 MAAP evaluation time varies for each MAAP case, based on achieving a plateau of the primary release category bins of concern (i.e., CsI, CsOH).

2 General Emergency declaration based on Emergency Action Level evaluation.

Table F.3-20
MACCS2 Base Case Mean Results Unit 2

Release Category	Dose (p-rem)	Offsite Economic Cost ($)	Freq. (/yr)	Dose-Risk (p-rem/yr)	OECR ($/yr)
H/E-BOC	1.61E+07	8.68E+10	8.32E-08	1.34E+00	7.22E+03
H/E	5.29E+06	4.66E+10	5.93E-08	3.14E-01	2.76E+03
H/I	5.66E+06	5.02E+10	1.90E-08	1.08E-01	9.54E+02
M/E	7.39E+06	4.39E+10	2.14E-07	1.58E+00	9.39E+03
M/I	3.86E+06	3.53E+10	9.27E-07	3.58E+00	3.27E+04
L/E	2.21E+05	3.19E+08	3.88E-07	8.57E-02	1.24E+02
L/I	7.09E+05	1.22E+09	1.45E-07	1.03E-01	1.77E+02
INTACT	2.17E+03	8.57E+05	7.45E-07	1.62E-03	6.38E-01
Frequency Weighted Totals			2.58E-06	7.11E+00	5.34E+04

Table F.5-1
LSCS Level 1 Importance List Review

EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
B--SYAVAILFAC---	9.62E-01	1.00E+30	PLANT AVAILABILITY FACTOR (AVERAGE OF BOTH UNITS)	This is the plant availability factor, which is included in every cutset and provides no insights related to potential means of reducing plant risk. No SAMAs identified.
RCVCL-2	1.00E+00	1.668	ACCIDENT CLASS II MARKER	This event is an accident class marker for loss of containment heat removal scenarios and does not represent any specific failure itself. The top contributors to this accident class are events related to adverse conditions caused by venting (over 70%) and HFEs related to the alignment of SPC (over 30%). LSCS is committed to installing a hard pipe vent, which will essentially eliminate the adverse environment condition in the RB after venting. Because this modification has not yet been implemented and is not reflected in the model or record, it has been designated as SAMA 1 for completeness. While already reliable, automating the initiation of SPC could further improve the reliability of the containment heat removal function (SAMA 2).
2HDOP-HD-VENTH--	9.00E-01	1.397	VENTING CREATES ADVERSE ENV. CONDITIONS FOR ALIGNMENT OF HD	The adverse environmental conditions after venting are caused by the lack of a hard pipe vent. LSCS is committed to installing a hard pipe vent, which will essentially eliminate this issue. Because this modification has not yet been implemented and is not reflected in the current model, it has been designated as SAMA 1 for completeness. This event is also used in the model for scenarios in which venting fails and containment failure results in an adverse environmental conditions. In conjunction with the hard pipe vent, a parallel, passive vent path could provide a means of ensuring that the containment failure occurs through a rupture disk with a scrubbed path from the wetwell (SAMA 3).

Table F.5-1
LSCS Level 1 Importance List Review

EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
2RPCDRPS-MECHFCC	2.10E-06	1.378	RPS MECHANICAL FAILURE	ATWS contributions are dominated by human control errors, which are represented by a number of HEP marker events and the JHEPs with which they are associated. One of the larger contributors to the scenarios including RPS mechanical failure is the HFE to bypass the low level interlock (~50%). Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4). Another contributor, at about 20%, is the failure to initiate SBLC. Automating system initiation could reduce these contributors (SAMA 5). Mechanical failure of the RPS itself is non-specific and provides no insights about potential changes that could be made to improve system reliability. No hardware changes have been identified.
2RHRXDHRRECLTH--	4.40E-01	1.304	FAIL TO RECOVERY DECAY HEAT REMOVAL LONG TERM	This event represents the probability of failing to repair the RHR system before PCPL is reached. No credible SAMAs have been identified that could justify a meaningful reduction in the repair probability itself, but there are means available to address other contributors to the scenarios that include this event. Over 80% of the contribution is related to failures resulting from an adverse RB environment cause by containment venting. LSCS is committed to installing a hardened vent (SAMA 1) that will effectively eliminate these types of events (no vent path failure). Of the remaining contributors, CCF

Table F.5-1
LSCS Level 1 Importance List Review

EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				plugging of the ECCS suction strainers is significant. Installing a connection from the RHRSW system on the RHR pump suction line could provide a means of back flushing the suction strainer and restoring flow (SAMA 6).
%TT	7.98E-01	1.28	TURBINE TRIP WITH BYPASS INITIATING EVENT	The largest contributors related to this initiating event are ATWS scenarios caused by RPS mechanical failure (~90%). As described in the disposition of event 2RPCDRPS-MECHFCC, the failure mode is non-specific and does not provide insights on how the system might be improved. A more effective approach to reducing the contributions from ATWS scenarios is to install a keylock MSIV low level isolation bypass switch, which would reduce the time required to bypass the interlock and provide more time margin for the actions in ATWS scenarios requiring bypass of the isolation logic. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4). Automating SBLC initiation could also reduce some of these contributors (SAMA 5).
2SY--RB-CT---F--	1.00E+00	1.235	COND. PROB. OF ECCS FAILURE DUE TO ENV. IN REACTOR BUILDING	This event represents the probability that the harsh RB environment cause by vent duct failure results in malfunction of ECCS equipment. LSCS is committed to installing a hard pipe vent, which will reduce the frequency of vent path failures to the point where they are no longer significant contributors (SAMA 1). No additional SAMAs required.
RCVCL-4A	1.00E+00	1.233	ACCIDENT CLASS IV MARKER	This event is an accident class marker for ATWS events, over 98% of which are linked to mechanical RPS failure.

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				As described in the disposition of event 2RPCDRPS-MECHFCC, the failure mode is non-specific and does not provide insights on how the system might be improved. A more effective approach to reducing the contributions from ATWS scenarios is to install a keylock MSIV low level isolation bypass switch, which would reduce the time required to bypass the isolation logic and provide more time margin the actions in ATWS scenarios requiring the bypass action. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4). Automating SBLC initiation could also reduce some of these contributors (SAMA 5).
2SY--PWR5PERCF--	1.00E+00	1.228	POWER LEVEL GREATER THAN 3%	This event represents the probability that reactor power is over 3% for failure to scram events (assumed to be true) and is part of the ATWS sequence definition. There are no SAMAs that would address this event itself, but the top contributors are the same as other ATWS scenarios, which are operator action failures related to level/power control. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				further (SAMA 4). Automating SBLC initiation could also reduce some of these contributors (SAMA 5).
2MSOP-AT-LVL-H--	1.00E+00	1.213	HEP: RPV LEVEL LOWERED BELOW LEVEL 1 SETPOINT DURING ATWS	This event represents the probability that reactor water level is lowered below level 1 in ATWS scenarios for which the MSIVs are initially open (i.e., not closed on high DW pressure). The assumed probability of 1.0 reflects the guidance in the EOPs that directs the operators to lower level to below the Level 1 MSIV closure setpoint. This is conservative as it assumes a 100% ATWS and as a result it forces the operators to perform low level MSIV isolation bypass for success. Over 70% of the contributors including this event include failure to bypass the low level MSIV interlock. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4). An additional contributor, at just under 20%, is failure to initiate SBLC. Automating SBLC initiation, which is a function available is some other BWRs, could reduce these contributors (SAMA 5).
2MSRXMSIVINLKH--	1.00E+00	1.155	HEP(REC): OPERATOR FAILS TO BYPASS LOW LEVEL MSIV INTERLOCK	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. The operator action failure probability is quantitatively accounted for in a JHEP event rather than in this marker event. The marker event may show up in

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				other cutsets with other JHEPs such that the importance of the marker event is the total of all the JHEPs associated with the HFE. The operator action represented by this marker is for the failure to bypass the low level MSIV isolation logic before level is lowered to control power. The high failure probability associated with this action is due to the short response time available and the relatively long time required to perform the action. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4).
RCVCL-1BE	1.00E+00	1.153	ACCIDENT CLASS IBE MARKER	This event is an accident class marker for LOCA scenarios and does not represent any specific failure itself. Over 90% are related to water hammer induced LOCAs and 55% are water hammer events related to the generation of a LOCA signal when a LOCA condition does not exist. When RHR SPC is placed in service in response to certain transient events that lead to a high DW pressure signal (LOCA signal), the discharge line can drain to the suppression pool in the ~45 seconds between RHR pump load shed and the time it is reloaded on the bus, which sets up a water hammer condition (RHR in SPC mode does not prevent the DW pressure from reaching 2 PSIG). Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				scenarios that set up these water hammer events at LSCS (SAMA 7).
2RHRXSPCINIT-H--	1.00E+00	1.147	HEP(REC): OPERATOR FAILS TO INITIATE SUPPRESSION POOL COOLING (NON-ATWS)	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. The action represents the failure to initiate SPC in time to prevent RPV blowdown on HCTL. The SPC initiation action is very reliable and for almost all of the contributors including this event, operator action dependence issues would prevent any SAMAs requiring human action from reducing risk in a meaningful way. For over 80% of the contributors, the total human error probability is either at or very close to the lowest allowable JHEP value. A potential means of reducing risk for these scenarios would be to automate SPC initiation on high suppression pool temperature in non-LOCA scenarios (SAMA 2). Most scenarios with SPC initiation failure also include the failure to vent containment, which represents the remaining means of containment heat removal. This leads to containment failure and an adverse environment in containment that fails ECCS equipment. Currently, venting containment will fail also lead to an adverse containment environment; however, the hard pipe event will prevent the release of containment atmosphere into the RB when venting (SAMA 1). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment reactor building (SAMA 3).
2RHRXSPCLATE-H--	1.00E+00	1.145	HEP(REC): OPERATOR FAILS TO INITIATE SPC LATE GIVEN EARLY FAILURE (COND PROB)	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. The action represents the failure to initiate SPC in time to preclude the need to vent containment at

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				the PCPL. The SPC initiation action is very reliable and for almost all of the contributors including this event, operator action dependence issues would prevent any SAMAs requiring human action from reducing risk in a meaningful way. For over 80% of the contributors, the total human error probability is either at or very close to the lowest allowable JHEP value. A potential means of reducing risk for these scenarios would be to automate SPC initiation on high suppression pool temperature in non-LOCA scenarios (SAMA 2). Most scenarios with SPC initiation failure also include the failure to vent containment, which represents the remaining means of containment heat removal. This leads to containment failure and an adverse environment in the reactor building that fails ECCS equipment. Currently, venting containment will also lead to an adverse reactor building environment; however, the hard pipe event will prevent the release of containment atmosphere into the RB when venting (SAMA 1). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3).
RCVSEQ-GTR-023	1.00E+00	1.145	ACCIDENT SEQUENCE GTR-023 MARKER	This event is a sequence marker representing scenarios where injection is provided by HPCS after FW failure, but SPC and venting fail. Failure of containment results in consequential failure of RPV injection. In over 99% of the cases, venting causes an adverse environment in the containment, which in most cases, leads to failure of ECCS. The installation of the hard pipe vent (SAMA 1), to which LSCS is committed, will essentially eliminate these types of failures. Operator failure to initiate SPC is a large contributor at about 40% and another way of mitigating these scenarios would be to automate

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				initiation of SPC (SAMA 2).
2RHSY-DRAINSPF--	1.00E+00	1.14	DISCH LINE DRAINS TO SUPPRESSION POOL CREATING A VOID	This event represents the probability that the RHR discharge line will drain to the suppression pool when power is interrupted to the RHR system is when it is running is SPC mode. For about 60% of the contribution, the scenario is related to the generation of a LOCA signal on high DW when an actual LOCA does not exist. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up water hammer events at LSCS (SAMA 7). Review of the cutsets also shows that over 90% of the contribution includes the HFE for failing to isolate the water hammer LOCA (in the form of JHEPs). However, the independent HEP for this action is low (2.3E-3) and is driven by the time available for response, so changes to training or plant procedures would not have a meaningful impact on the reliability of the action and no additional SAMAs are suggested.
%DLOOP	7.95E-03	1.135	DUAL UNIT LOSS OF OFF-SITE POWER INITIATING EVENT	The contributors to DLOOP are diverse, but over 40% include containment venting events that lead to adverse environmental conditions in the RB. LSCS is committed to installing a hardened vent (SAMA 1) that will effectively eliminate these types of events (no vent path failure). Another contributor is long term SBOs (~25%) where battery depletion fails injection. After installation of a hardened containment vent at LSCS, a viable means of containment heat removal will be available in SBO scenarios. The diesel fire pump is a currently proceduralized injection source that can be used in an SBO, but this low pressure injection source would only be available until the SRVs close after battery depletion (RPV re-pressurization would prevent continued injection). Use of a portable generator to provide long

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				term power to the 125 VDC battery chargers would provide a means of maintaining diesel fire pump makeup indefinitely (SAMA 8).
RCVCL-IBL	1.00E+00	1.129	ACCIDENT CLASS IBL MARKER	This event is an accident class marker for long term SBO scenarios and does not represent any specific failure itself. After installation of a hardened containment vent at LSCS, a viable means of containment heat removal will be available in SBO scenarios. The diesel fire pump is a currently proceduralized injection source that can be used in an SBO, but this low pressure injection source would only be available until the SRVs close after battery depletion (RPV re-pressurization would prevent continued injection). Use of a portable generator to provide long term power to the 125 VDC battery chargers would provide a means of maintaining diesel fire pump makeup indefinitely (SAMA 8). Smaller contributors include fire protection flooding events with failure of the isolation valve between the FPS and the Service Water System (SWS). Other isolation points and mitigation methods are potentially available, but the reliability of flood mitigation could be improved by developing procedures to direct specific actions for specific flood events (SAMA 9).
2CVRXVENT----H--	1.00E+00	1.128	HEP(REC): OPERATOR FAILS TO INITIATE PRIMARY CONTAINMENT VENTING	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. The event represents the HFE for initiating the containment vent. The results show that essentially all of the cutsets that include this HFE also include the HFE for initiating SPC and the JHEPs for these events are at the lowest allowable JHEP value. The implication is that the heat removal function is already highly reliable and that current HRA methods cannot reliably assess

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				the failure probabilities of the contributing JHEPs. Because of this, the benefit of changes to reduce these contributors further would be questionable, but eliminating the requirement for the operators to perform these tasks is a mathematical means of demonstrating a reduction in risk. Potential means of accomplishing this goal would be to either automate SPC initiation on high suppression pool temperature (SAMA 2) or by installing a rupture disk in parallel with the remotely controlled hard pipe vent path (SAMA 3).
2RHRX-TRIPLK-H--	1.00E+00	1.125	HEP(REC): OPERATOR FAILS TO DETECT & ISOLATE SMALL RHR FLOOD FROM WATER HAMMER E	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. The event represents the failure of operators to isolate a water hammer induced LOCA in the RHR system. For about 2/3 of the contribution, the scenario is related to the generation of a LOCA signal on high DW pressure when an actual LOCA does not exist. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up water hammer events at LSCS (SAMA 7). Review of the isolation HEP itself shows that it is driven by the time available for response, so changes to training or plant procedures would not have a meaningful impact on the reliability of the action and no SAMAs related to procedure or training improvements are suggested.
2CN--RUPT-DWBF--	8.58E-02	1.121	DW BODY RUPTURE	This event represents the probability of a drywell failure given containment overpressurization. Over 60% of the contributors are related to the failure to the HFEs for containment vent failure and/or SPC initiation failure. These actions are reliable, but eliminating the requirement for the operators to perform these tasks is a potential means of reducing risk for the scenarios

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				leading to DW rupture. This could be accomplished by either automating SPC initiation on high suppression pool temperature (SAMA 2) or by installing a rupture disk in parallel with the remotely controlled hard pipe vent path (SAMA 3).
%TIA	9.92E-03	1.121	LOSS OF INSTRUMENT AIR INITIATING EVENT	This represents the loss of instrument air initiating event, which is modeled to include the trailer mounted air compressor. The contributors to the loss of instrument air (LOIA) are diverse, but about 30% are related to water hammer induced LOCAs caused by high DW pressure signals in transients. These events could be prevented by altering the LOCA signal to require a coincident low RPV water level signal (SAMA 7). In about 60% of the contributors including %TIA, the ability to vent is failed by the initiator, followed by failure to recover IA, and then containment failure leads to loss of injection due to adverse containment environment. Currently, LSCS has a procedure to direct the use of portable pneumatic bottles to support venting when IA has failed; however, credit is not taken for the procedure due to the potential for vent path rupture and radiation shine. Installation of the reliable hard pipe vent will provide a means of operating the containment vent when normal support systems have failed (SAMA 1).
RCVSEQ-DLOP-041	1.00E+00	1.12	ACCIDENT SEQUENCE DLOP-041 MARKER	This event is an accident sequence marker for LOCA induced LOOP scenarios and does not represent any specific failure itself. For about 70% of the contribution, the scenario is related to the generation of a LOCA signal on high DW when an actual LOCA does not exist. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up water hammer events at LSCS (SAMA 7).

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
OSPR30MIN-GR	8.25E-01	1.12	FAILURE TO RECOVER OSP WITHIN 30 MINUTES (GRID RELATED LOOP EVENT)	This event represents the failure to recover offsite power within 30 minutes for grid related LOOP events. For over 70% of the contribution, the scenario is related to the generation of a LOCA signal on high DW pressure when an actual LOCA does not exist. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up water hammer events at LSCS (SAMA 7).
BFPOP-DFPENV1H--	5.00E-01	1.116	HEP: OP FAILS TO ALIGN DFP DUE TO ADVERSE ENV IN TB (VENT TO STEAM TUNNEL)	This event represents the probability that the operators will fail to align RPV injection from the diesel fire pump in an adverse environment caused by either venting or containment failure. The reliable hard pipe vent (SAMA 1) would mitigate over 90% of the scenarios including this event. For about 33% of the initiators, containment vent is successful, but the vent path ruptures and the containment atmosphere enters the RB, TB, and other areas. This evolution will be prevented by the installation of the reliable hard pipe vent because the vent path would not rupture after successful vent. For another 33% of the contributors, the vent capability is disabled by loss of instrument air. The reliable hard pipe vent will provide a means of operating the containment vent after loss of normal support systems and containment overpressurization could be avoided. An additional 25% of the contribution is related to vent failure after LOOP. Again, the reliable hard pipe vent will provide a means of venting after loss of normal support systems, such as power.
%TC	1.33E-01	1.115	LOSS OF CONDENSER VACUUM INITIATING EVENT	For this initiator, about 70% of the contributors are loss of containment heat removal evolutions. About half of these are driven by failure to vent after RHR hardware failure and the other half are related to manual SPC

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				initiation failures. Installation of a rupture disk in parallel with the remotely controlled hard piped vent path would address these cases (SAMA 3). Some of the venting failures are related to vent control failures, which result in loss of ECCS NPSH and/or vent path rupture. Loss of NPSH would be less of an issue with a hard pipe vent because actions could be taken in the RB and TB to align alternate injection after venting. Automating SPC on high pool temperature could also technically mitigate the cases in which SPC fails due to operator error (SAMA 2). The remaining contributors are ATWS sequences, many of which could be mitigated by automating SBLC (SAMA 5) or by installing a MSIV low level isolation bypass switch. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4).
RCVSEQ-ATW1-037	1.00E+00	1.113	ACCIDENT SEQUENCE ATW1-037 MARKER	This event is an accident sequence marker for ATWS events which include failures of early and late level/power control. Almost all of the contributors include mechanical failure of RPS, but as described in the disposition of event 2RPCDRPS-MECHFCC, the failure mode is non-specific and does not provide insights on how the system might be improved. A more effective approach to reducing the contributions from ATWS scenarios is to install a keylock MSIV low level isolation bypass switch (~75% of the contributors), which would reduce the time required to bypass the isolation logic and provide more time margin for the actions in ATWS scenarios requiring the bypass action. In order to improve the effectiveness of this enhancement, the EOP

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				step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4). Automating SBLC system initiation could also address about 60% of these contributors (SAMA 5).
2SLRX-LVLCTRLH--	1.00E+00	1.105	HEP(REC): OPERATOR FAILS TO LOWER LEVEL EARLY (ATWS)	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. The action itself if for level control in an ATWS, which consists of reducing FW flow into the RPV to reduce power (governed by a "hard card" in the MCR). The HEP for this action is dominated by the result from the time reliability curve and reflects the short available time for cognitive work in the scenario. The "hard card" guidance for level control is considered to streamline the control action as much as is reasonably possible for the existing control configuration. A potentially effective approach to reducing the contributions from ATWS scenarios is to install a keylock MSIV low level isolation bypass switch (~79% of the contributors), which would reduce the time required to bypass the isolation logic and provide more time margin for the actions in ATWS scenarios requiring the bypass action. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4). Automating SBLC system initiation could also address about 60% of these contributors (SAMA 5).

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
DGRECOV-7HR	1.00E+00	1.093	DIESEL GENERATOR RECOVERY WITHIN 7 HOURS	The event represents failure to recover the EDGs by 7 hours, at which time the station batteries are expected to be depleted (with successful load shed). Continued availability of DC power alone would not allow for indefinite RCIC operation, but the use of a portable 480V AC generator to support the SRVs and instrumentation could help maintain low pressure injection (SAMA 8). When considered in conjunction with the planned reliable hard pipe vent (SAMA 1) and fire protection or other injection methods, long term SBO mitigation is possible.
DLOOP-IE-SW	3.84E-01	1.092	COND. PROBABILITY DLOOP DUE TO SEVERE WEATHER EVENT	For the DLOOP initiating event, containment venting is failed due to unavailability of air. In over 50% of the DLOOP contributors, core damage results because containment overpressurization failure leads to loss of injection due to adverse containment environment. Currently, LSCS has a procedure to direct the use of portable pneumatic bottles to support venting when IA has failed; however, credit is not taken for the procedure due to the potential for vent path rupture and radiation shine. Installation of the reliable hard pipe vent will provide a means of operating the containment vent when normal support systems have failed (SAMA 1). In most of the remaining cases, SBO conditions force use of RCIC for injection until battery depletion. Providing a system to maintain DC power alone would not allow for indefinite RCIC operation due to HCTL impingement, but the use of a portable 480V AC generator to support the SRVs and instrumentation could support long term low pressure injection (SAMA 8). When considered in conjunction with the planned reliable hard pipe vent (SAMA 1) and fire protection or other injection methods, long term SBO mitigation is possible.

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
2ACSYLOOPLOCA---	2.40E-02	1.091	COND PROB OF A LOOP GIVEN A LOCA SIGNAL	For over 90% of the contributors that include a consequential LOOP after a LOCA signal, the scenario is related to the generation of a LOCA signal on high DW pressure when an actual LOCA does not exist. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up water hammer events at LSCS (SAMA 7).
2FWRXMOV10AB-H--	1.00E+00	1.087	HEP(REC): OPERATOR FAILS TO CLOSE THE TDRFP DISCHARGE MOVS 2FW010A & B	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. The action itself is for closing the turbine driven feedwater pump discharge valves in time to prevent RPV overfill or hotwell depletion. The flow control for these pumps is provided by pump speed control rather than regulating valve and when the pumps are tripped, the flowpath remains open. When reactor pressure is reduced, flow from the condensate pumps or heater drain system can flow in an uncontrolled manner into the RPV. The HEP is driven by the time reliability component and the execution component for two valve closures, which presents limited opportunity for improvement, but even if the HEP could be lowered, over 75% of the contribution including the event is linked to JHEPs at the lowest allowable JHEP value, so no reduction could be realized for those cases. The JHEPs including this action also include failure to manually initiate SPC. The frequency of these contributors could be reduced by changing the logic to auto close the TDRFP discharge valves when the pumps are tripped or are not running (SAMA 10).
2CVRX2INCHVNTH--	1.00E+00	1.086	HEP(REC) :OPERATOR FAILS TO OPEN 2" LINES TO MAINTAIN DW	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. For over 93% of the contributors that

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
			PRESSURE BELOW HI DW SE	include this HFE, the scenario is related to the generation of a LOCA signal on high DW pressure when an actual LOCA does not exist. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up water hammer events at LSCS (SAMA 7).
2RHRX-LOCA---H--	1.00E+00	1.082	HEP(REC): OPERATORS FAIL TO PREVENT RHR AUTO START WITH LOCA SIGNAL AT T=0	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. The HFE itself is for preventing start of RHR before the system is reloaded onto the emergency bus after it is shed in LOCA/LOOP case. Failure to do so sets up a water hammer condition because the discharge line may drain to the suppression pool while the RHR pump is being re-sequenced onto the emergency bus. Because there is less than one minute to respond to the circumstances requiring the action to prevent RHR start, no credit is taken for the action and the potential for HEP improvement is limited. The scenarios that include this HFE are all related to the generation of a LOCA signal on high DW pressure when an actual LOCA does not exist. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up water hammer events at LSCS (SAMA 7).
%FSRB12	1.05E-04	1.079	FPS PIPE RUPTURE IN REACTOR BLDG.	This initiator is a fire protection system rupture in the reactor building that results in failure of ECCS equipment required to prevent core damage. About 80% of the contributors for this initiating event include fire protection flooding events with failure of the isolation valve between the FPS and the SWS. Other isolation points and mitigation methods are potentially available, but

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				they are not credited due to the limited guidance that is available. The reliability of flood mitigation could be improved by developing procedures to direct specific actions for specific flood events (SAMA 9). Most of the remaining contribution is from the failure to trip the fire protection pumps in time to prevent equipment damage in the RB. Providing a manual trip override switch for the fire pumps in the MCR would reduce the time required to shut down the fire pump. If procedures were developed to direct isolation of the FP070 and FP080 valves in conjunction with the MCR trip capability, the time required to terminate the reactor building fire protection floods would be significantly reduced and the reliability of the mitigation action would be improved (SAMA 11).
RCVSEQ-TBRBFL-017	1.00E+00	1.078	ACCIDENT SEQUENCE TBRBFL-017 MARKER	This event is an accident sequence marker for fire protection floods in the reactor building and does not represent any specific failure itself. It is completely tied to three cutsets in which either the SWS to FPS isolation valves fail to close or the FPS pump trip fails. Other isolation points and mitigation methods are potentially available, but they are not credited due to the limited guidance that is available. The reliability of flood mitigation could be improved by developing procedures to direct specific actions for specific flood events (SAMA 9). Most of the remaining contribution is from the failure to trip the fire protection pumps in time to prevent equipment damage in the RB. Providing a manual trip override switch for the fire pumps in the MCR would reduce the time required to shut down the fire pump. If procedures were developed to direct isolation of the FP070 and FP080 valves in conjunction with the MCR trip capability, the time required to terminate the reactor building fire protection floods would be significantly

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				reduced and the reliability of the mitigation action would be improved (SAMA 11).
2CN-LEAK-WWAF--	1.17E-01	1.076	WW AIRSPACE LEAK	This event represents the probability of containment failure in the suppression pool airspace on containment overpressurization. Venting failure, which leads to containment failure, is split between human error and support system unavailability. For the cases with operator error, the action is almost always paired with failure to initiate SPC. These actions are reliable, but eliminating the requirement for the operators to perform these tasks is a potential means of reducing risk for the scenarios leading to WW rupture. This could be accomplished by either automating SPC initiation on high suppression pool temperature (SAMA 2) or by installing a rupture disk in parallel with the remotely controlled hard pipe vent path (SAMA 3). The reliable hard pipe vent will not only prevent rupture of the vent path, but will also provide a means of venting containment when normal support systems are unavailable (SAMA 1).
2RX-WHLTRIPL3H--	4.70E-03	1.076	2CVOP2INCHVNTH-- 2RHOP-LOCA---H-- 2RHOP-TRIPLK-H--	This event is a JHEP representing the failure to vent the DW to prevent a high containment pressure/LOCA signal, failure to prevent start of RHR after reload of the emergency bus after LOOP, and failure to isolate the water hammer induced LOCA. Over 94% of the scenarios that include this JHFE are related to the generation of a LOCA signal on high DW pressure when an actual LOCA does not exist. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up water hammer events at LSCS (SAMA 7).
2CN--RUPT-WWAF--	1.11E-01	1.072	WW AIR SPACE RUPTURE	This event represents the probability of containment

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				failure in the suppression pool airspace on containment overpressurization. Venting failure, which leads to containment failure, is split between human error and support system unavailability. For the cases with operator error, the action is almost always paired with failure to initiate SPC. These actions are reliable, but eliminating the requirement for the operators to perform these tasks is a potential means of reducing risk for the scenarios leading to WW rupture. This could be accomplished by either automating SPC initiation on high suppression pool temperature (SAMA 2) or by installing a rupture disk in parallel with the remotely controlled hard pipe vent path (SAMA 3). The reliable hard pipe vent will not only prevent rupture of the vent path, but will also provide a means of venting containment when normal support systems are unavailable (SAMA 1).
2IARXRCOVERIAH--	1.00E-01	1.07	HEP: OP FAILS TO RESTORE IA / SA FOR VENTING (NON LOOP OR DLOOP)	This event represents the failure to repair IA/SA after it has failed, which is part of the initiating event in 99% of contributors in which it is included. The initiating event includes failures of the portable air compressor, so use of that component is not a separate option that could be used to mitigate these scenarios. The reliable hard pipe vent will provide a means of venting after loss of normal support systems, such as air or power (SAMA 1).
RCVCL-1C	1.00E+00	1.069	ACCIDENT CLASS IC MARKER	This event is an accident class marker for mitigated ATWS events without adequate makeup and does not represent any specific failure itself. In about 60% of the cases, failure to bypass the MSIV low level isolation logic results in loss of the power conversion system. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4). The remaining contributors are mostly comprised of HFEs related to depressurization failure. HPCS is generally available, but not used because of reactivity issues related to the injection location. If a cross-tie line were installed between HPCS and the FW injection line, an alternate means of providing high pressure injection to the core could be provided for ATWS scenarios (SAMA 12).
RCVSEQ-GTR-013	1.00E+00	1.065	ACCIDENT SEQUENCE GTR-013 MARKER	This event is an accident sequence marker for loss of containment heat removal cases where venting failure lead to containment rupture and subsequent injection system failure. About 2/3 of the contributors are driven by operator failure to vent after RHR hardware failure and the other 1/3 are related to operator failure to vent after manual SPC initiation failures. Installation of a rupture disk in parallel with the remotely controlled hard piped vent path would address these cases (SAMA 3). Automating SPC on high pool temperature could also mathematically mitigate the cases in which SPC fails due to operator error (SAMA 2), although HRA methodology limitations make the true benefits difficult to assess.
2RHSYLEAKB---L--	9.00E-02	1.056	RH TRAIN B FAILS DUE TO EXCESSIVE LEAKAGE FOLLOWING WATER HAMMER	This event represents the probability that a leak large enough to fail the corresponding RHR train occurs after a water hammer event. For about 70% of the contribution, the scenario is related to the generation of

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				a LOCA signal on high DW pressure when an actual LOCA does not exist. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up water hammer events at LSCS (SAMA 7). Review of the cutsets also shows that over 90% of the contribution includes the HFE for failing to isolate the water hammer LOCA (in the form of JHEPs). However, the independent HEP for this action is low (2.3E-3) and is driven by the time available for response, so changes to training or plant procedures would not have a meaningful impact on the reliability of the action and no additional SAMAs are suggested.
2RHSYLEAKA---L--	9.00E-02	1.056	RH TRAIN A FAILS DUE TO EXCESSIVE LEAKAGE FOLLOWING WATER HAMMER	This event is represents the probability that a leak large enough to fail the corresponding RHR train occurs after a water hammer event. For about 70% of the contribution, the scenario is related to the generation of a LOCA signal on high DW pressure when an actual LOCA does not exist. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up water hammer events at LSCS (SAMA 7). Review of the cutsets also shows that over 90% of the contribution includes the HFE for failing to isolate the water hammer LOCA (in the form of JHEPs). However, the independent HEP for this action is low (2.3E-3) and is driven by the time available for response, so changes to training or plant procedures would not have a meaningful impact on the reliability of the action and no additional SAMAs are suggested.
%TM	5.01E-02	1.056	MSIV CLOSURE INITIATING EVENT	About half of the contributors for the MSIV closure initiators result in containment failure after failure to initiate SPC. While already reliable, automating the

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				initiation of SPC could further improve the reliability of the containment heat removal function (SAMA 2). Most scenarios with SPC initiation failure also include the failure to vent containment, which represents the remaining means of containment heat removal. This leads to containment failure and an adverse environment in the reactor building that fails ECCS equipment. Currently, venting containment will also lead to an adverse reactor building environment; however, the hard pipe event will prevent the release of containment atmosphere into the RB when venting (SAMA 1). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3). The remaining contributors are mostly related to ATWS caused by 2RPCDRPS-MECHFCC, which is addressed separately on this list.
RCVSEQ-DLOP-014	1.00E+00	1.055	ACCIDENT SEQUENCE DLOP-014 MARKER	This event is an accident sequence marker for long term DLOOP events with loss of containment heat removal and containment vent failure, which leads to containment rupture. Venting failures are primarily caused by the initiating event, which fails the support systems for the current containment vent design. The reliable hard pipe vent will provide a means of operating the containment vent after loss of normal support systems and containment overpressurization could be avoided (SAMA 1).
2SLRX-IN-LATEH--	1.00E+00	1.055	HEP(REC): OPERATOR FAILS TO INITIATE SBLC LATE (COND PROB)	Failure to initiate SBLC could be mitigated by automating SBLC initiation (SAMA 5). About 2/3 of the contributors including SBLC initiation failure also include failure to bypass the low level MSIV interlock. Installing a keylock MSIV low level isolation bypass switch would

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4).
2MSOPMSIVINLKH--	7.00E-01	1.054	HEP: OPERATOR FAILS TO BYPASS LOW LEVEL MSIV INTERLOCK	Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions (SAMA 4).
OSPR20HR-SW	1.33E-01	1.051	FAILURE TO RECOVER OSP WITHIN 20 HOURS (SEVERE WEATHER LOOP EVENT)	OSPR20HR-SW represents the failure to recover offsite power by 20 hours after a severe weather induced LOOP. Over 90% of the contributors including this event are from sequence DLOP-014, which are long term DLOOP events with loss of containment heat removal and containment vent failure. These conditions lead to containment rupture. The venting failures are primarily caused by the initiating event, which fails the support systems for the current containment vent design. The reliable hard pipe vent will provide a means of operating the containment vent after loss of normal support systems and containment overpressurization could be avoided (SAMA 1).
2ADRX-INHIBITH--	1.00E+00	1.049	HEP(REC): OPERATORS INHIBIT ADS FOR NON-ATWS ACCIDENT SCENARIO	This action represents the probability that the operators will, contrary to procedure, inhibit ADS in non-ATWS scenarios. The operator interviews suggest that they are all very familiar with the LSCS EOPs and the fact that LSCS deviates from the BWROG EPG/SAGs, that they

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				are well trained on the procedure, and that the procedures and cues for how to address ADS are clear. Plant experience shows, however, that ADS inhibit may occur in non-ATWS scenarios. No training or procedure enhancements have been identified that could significantly reduce the probability of inhibiting ADS in non-ATWS scenarios. In addition, this type of error is an "error of commission", for which there are no generally accepted quantification methods. For LSCS, it is based on plant operating experience. About 80% of the contributors that include this event also include failures to initiate SPC. Failure to initiate SPC could be mitigated by automating SPC initiation on high SPC temperature (SAMA 2); however, the true benefit of this enhancement is difficult to assess because the dominant human reliability terms are limited by the lowest allowable JHEP value.
2CVOPVENT----H--	6.60E-03	1.049	HEP: OPERATOR FAILS TO INITIATE PRIMARY CONTAINMENT VENTING	This event represents the independent failure probability of the containment venting action, which means that the contributors including this action either contain no other HFEs or that the venting failure is independent of other HFEs in the evolution. The independent action for venting is relatively reliable; the operators are familiar with the action, are well trained on the action, and the procedures directing the action are clear. The HEP is dominated by the execution failure probability, which includes contributors from the many jumper installation steps. The reliable hard pipe vent (SAMA 1) will simplify the containment venting process and reduce the risk of these contributors. In conjunction with the hard pipe vent, a parallel, passive vent path could provide a means of ensuring that the containment failure occurs through a rupture disk with a scrubbed path from the wetwell (SAMA 3) in the event that manual venting fails.

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
%TBCCWFACTOR	1.00E+00	1.048	LOSS OF TBCCW INITIATING EVENT	This event is an initiating event marker used to identify the failures from the loss of TBCCW initiating event fault tree. For about 80% of the contribution, the scenario is related to the generation of a LOCA signal on high DW pressure when an actual LOCA does not exist. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up water hammer events at LSCS (SAMA 7).
%TF	5.65E-02	1.047	LOSS OF FEEDWATER INITIATING EVENT	Loss of FW events include diverse contributors, but about 45% include failures to vent containment. To mitigate manual venting failures, a parallel, passive vent path could be installed in conjunction with the hard pipe vent (SAMA 1) to provide a means of ensuring that the containment failure occurs through a rupture disk with a scrubbed path from the wetwell (SAMA 3). About 1/3 of the contribution includes failure to manually initiate SPC, which could be mitigated by automating SPC initiation (SAMA 2). However, the true benefits of this enhancement and SAMA 3 are difficult to assess because the dominant human reliability terms are limited by the lowest allowable JHEP value. About 30% of the contributors are ATWS scenarios. Installing a low level isolation bypass switch in the MCR (SAMA 4) would provide a means of reducing the risk of these scenarios.
2RHRX-SPCVD--H--	1.00E+00	1.046	HEP(REC): OPERATORS START RHR WITHOUT FILL AND VENT	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. In this case, the event represents the failure to fill and vent an ECCS system before starting the pumps after an evolution where the discharge line has been drained. For scenarios in which a LOOP occurs when RHR is in operation (for SPC, generally), the piping will drain to the suppression pool and the lines

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				must be re-filled before restarting the pump to prevent water hammer. The independent HEP for this action is conservatively quantified as 2.5E-02. The action is not time stressed given that the available diagnosis time is over 3 hours and the main contributor to the HEP is the execution component. The HRA for the fill and vent action includes some steps that would not be performed in an accident scenario (those that require drywell entry) and it does not credit a check of the RHR discharge pressure alarm to identify fill and vent failures. This is a proceduralized check that would identify conditions in which the fill and vent process was performed incorrectly. If this check were to be credited, the independent HEP would be reduced by over an order of magnitude and because this HEP is the lead HEP in the dependent action assessments, the JHEPs would be similarly be reduced. These events are not considered to be significant contributors and no SAMAs are suggested.
2CN--LEAK-DWBF--	7.46E-02	1.046	DW BODY LEAK	About half of the contributors with DW body leaks occur after failure to initiate SPC. While already reliable, automating the initiation of SPC could further improve the reliability of the containment heat removal function (SAMA 2). Most scenarios with SPC initiation failure also include the failure to vent containment, which represents the remaining means of containment heat removal. This leads to containment failure and an adverse environment in the reactor building that fails ECCS equipment. Currently, venting containment will also lead to an adverse reactor building environment; however, the hard pipe event will prevent the release of containment atmosphere into the RB when venting (SAMA 1). For the remaining half of the contributors that lead to DW body leaks, venting is failed by the initiating

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				event. If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3).
2SLRX-LATELVLH--	1.00E+00	1.044	HEP(REC): OPERATOR FAILS TO CONTROL LEVEL LATE IN ATWS (COND PROB)	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. The HFE itself is for controlling level adequately to reduce reactivity and ultimately prevent violation of the PCP. Over 99% of the contributors that include level control failures also include the HFE to bypass the low level interlock. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4).
2ADRX-TRANS--H--	1.00E+00	1.043	HEP(REC): OPERATOR FAILS TO MANUALLY DEPRESSURIZE THE RPV (TRANSIENT)	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. The HFE itself represents the failure to depressurize the RPV in a transient after incorrectly inhibiting ADS. The operators are well trained on depressurization and on not inhibiting ADS in non-ATWS scenarios and no procedure changes or training enhancements have been identified that could have a meaningful impact on the action reliabilities. In about 90% of the scenarios in which depressurization failure

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				occurs, the action is required because failure to initiate SPC leads to containment failure and subsequent loss of the operating high pressure injection system. These evolutions could be mitigated by automating SPC initiation (SAMA 2). However, the true benefits of this enhancement are difficult to assess because the dominant human reliability terms are limited by the lowest allowable JHEP value.
2SY--VENT1---FCC	9.99E-03	1.042	CCF OF HPCS & CRD & LPCI & LPCS GIVEN VENT TO STEAM TUNNEL	This event represents the probability that the cited injection systems fail due to an adverse environment caused by venting. In over 93% of the contribution, venting is successfully performed, but the pathway fails. The reliable hard pipe vent will address these scenarios (SAMA 1).
2RX-WH-V-TPL2H--	1.30E-03	1.041	2RHOP-SPCVD--H-- 2RHOP-TRIPLK-H--	This event is a joint HEP for the actions to 1) fill/vent RHR prior to system start after a discharge leg draindown, and 2) locate and isolate a leak caused by the water hammer event from system start. For scenarios in which a LOOP occurs when RHR is in operation (for SPC, generally), the piping will drain to the suppression pool and the lines must be re-filled before restarting the pump to prevent water hammer. The independent HEP for this action is conservatively quantified as 2.5E-02. The action is not time stressed given that the available diagnosis time is over 3 hours and the main contributor to the HEP is the execution component. The HRA for the fill and vent action includes some steps that would not be performed in an accident scenario (those that require drywell entry) and it does not credit a check of the RHR discharge pressure alarm to identify fill and vent failures. This is a proceduralized check that would identify conditions in which the fill and vent process was performed

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				incorrectly. If this check were to be credited, the independent HEP would be reduced by over an order of magnitude and because this HEP is the lead HEP in the dependent action assessments, the JHEPs would be similarly be reduced. These events are not considered to be significant contributors and no SAMAs are suggested.
RCVSEQ-ATW1-031	1.00E+00	1.039	ACCIDENT SEQUENCE ATW1-031 MARKER	This event is an accident sequence marker for ATWS scenarios with loss of the condenser. About 70% of the contributors include failure to bypass the low level MSIV isolation logic. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4).
2RHSYSTARTB-----	5.00E-01	1.038	RH TRAIN B IS PLACED INTO OPERATION FOLLOWING A TRANSIENT	This event represents the probability that the RHR B train will be placed in service after a transient to respond to the requirement for containment heat removal. The events are related to water hammer induced LOCAs, which for the contributors including this event are related to the generation of a LOCA signal when a LOCA condition does not exist. When RHR SPC is placed in service in response to certain transient events that lead to a high DW pressure signal (LOCA signal), the discharge line can drain to the suppression pool in the ~45 seconds between RHR pump load shed and the

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				time it is reloaded on the bus, which sets up a water hammer condition. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up these water hammer events at LSCS (SAMA 7).
2RHSYSTARTA-----	5.00E-01	1.038	RH TRAIN A IS PLACED INTO OPERATION FOLLOWING A TRANSIENT	This event represents the probability that the RHR A train will be placed in service after a transient to respond to the requirement for containment heat removal. The events are related to water hammer induced LOCAs, which for the contributors including this event are related to the generation of a LOCA signal when a LOCA condition does not exist. When RHR SPC is placed in service in response to certain transient events that lead to a high DW pressure signal (LOCA signal), the discharge line can drain to the suppression pool in the ~45 seconds between RHR pump load shed and the time it is reloaded on the bus, which sets up a water hammer condition. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up these water hammer events at LSCS (SAMA 7).
2CVOP-VNTCNT-H--	7.20E-02	1.037	HEP: OPERATOR FAILS TO CONTROL VENT WITHIN PROCEDURALIZED PRESSURE BAND	This HFE represents the independent failure probability for controlling venting to maintain pressure between 50 and 60 psig to both 1) prevent vent path failure and 2) to maintain NPSH for ECCS injection. The HEP is dominated by the cognitive time reliability curve contribution, which is based on the assumption that 5 minutes are available between the cue and the end of the system window, and a 1 minute manipulation time. This is a conservative representation of the time available for the cognitive work because, as stated in the HRA, there are many hours available prior to venting during which preparations for the action can be made.

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				Ultimately, the reliable hard pipe vent will mitigate these events (SAMA 1). The hardened vent path will preclude the need for this action for vent path protection. In addition, without vent path failures, there will be no adverse environmental conditions to prevent alignment of alternate injection systems if NPSH is lost on the operating ECCS.
RCVSEQ-GTR-011	1.00E+00	1.035	ACCIDENT SEQUENCE GTR-011 MARKER	This event is an accident sequence marker for loss of condenser transient scenarios with loss of containment heat removal and successful containment vent, which leads to an adverse RB environment due to vent duct rupture and injection system failure. The reliable hard pipe vent will mitigate failure of the vent path and mitigate these scenarios (SAMA 1). The loss of decay heat removal contributors are diverse, but some contributors could be eliminated by automating SPC initiation (SAMA 2).
RCVCL-1A	1.00E+00	1.034	ACCIDENT CLASS IA MARKER	This accident class is for loss of injection with the RPV at high pressure. Over 83% of the contributions are related to 125V DC power failures, most of which are related to 125V DC bus failures with a smaller contribution from CCF of all five 125V battery chargers. These failures could be mitigated by providing a portable DC source and a means of connecting it to ESF DC distribution panel 1(2)11Y to support RCIC operation and long term RPV depressurization and with FPS injection (SAMA 14).
RCVCL-5	1.00E+00	1.033	ACCIDENT CLASS V MARKER	This accident class is for containment bypass scenarios, over 90% of which are related to ISLOCA events in the RHR and LPCS systems. Failure to isolate the pathway is the dominant contributor, which leads directly to core damage due to lack of a long term inventory makeup source. A potential means of providing an indefinite

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				source of RPV makeup would be to tie the LPCS system to the RHRSW system and use the RHRSW pumps to provide injection flow to the RPV (SAMA 15).
2RX-SL-MS2--3H--	4.70E-02	1.033	2SLOP-LVLCTRLH-- 2MSOPMSIVINLKH-- 2SLOP-LATELVLH--	This joint HEP represents failure to bypass the MSIV low level isolation logic, early level control, and late level control in ATWS events. The high failure probability associated with the action to bypass the MSIV low level isolation logic is due to the short response time available and the relatively long time required to perform the action. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4).
BFPRX-DFPENV-H--	1.00E+00	1.032	HEP(REC): OP FAILS TO ALIGN DFP DUE TO ADVERSE ENV IN TB (VENT TO RB OR CNTNMT F	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. The event is always combined with failure to initiate SPC. The SPC initiation action is very reliable and for almost all of the contributors including this event, operator action dependence issues would prevent any SAMAs requiring human action from reducing risk in a meaningful way. In these cases, the total human error probability is either at or very close to the lowest allowable JHEP value. A potential means of reducing risk for these scenarios would be to automate SPC initiation on high suppression pool temperature in non-LOCA scenarios (SAMA 2). Most scenarios with SPC

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				initiation failure also include the failure to vent containment, which represents the remaining means of containment heat removal. This leads to containment failure and an adverse environment in the reactor building (RB) and/or turbine building (TB) that prevents DFP alignment. Currently, venting containment can also lead to an adverse environment outside of containment; however, the hard pipe event will prevent the release of containment atmosphere into the RB and/or TB when venting (SAMA 1). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3).
2RX-SL-MS1--3H--	4.50E-02	1.031	2SLOP-LVLCTRLH-- 2MSOPMSIVINLKH-- 2SLOP-IN-LATEH--	This joint HEP represents failure to bypass the MSIV low level isolation logic, early level control, and late SBLC injection in ATWS events. The high failure probability associated with the action to bypass the MSIV low level isolation logic is due to the short response time available and the relatively long time required to perform the action. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4). Automating SBLC initiation could also reduce some of these contributors (SAMA 5).

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
2RHPPISLOCA--R--	1.00E+00	1.031	RH LOW PRESSURE PIPING RUPTURES DURING ISLOCA EVENT	This event is related to ISLOCA events in the RHR and LPCS systems, 97% of which are linked to failure of the MOV to isolate (leads directly to core damage due to lack of a long term inventory makeup source). A potential means of providing an indefinite source of RPV makeup would be to tie the LPCS system to the RHRSW system and use the RHRSW pumps to provide injection flow to the RPV (SAMA 15).
1FPXV-1FP058-K--	7.43E-04	1.031	L.O. MANUAL VALVE 1FP058 FTC	About 97% of the contributors including this event are attributable to a single cutset in which a fire protection pipe breaks in the reactor building and 1FP058 fails to close. Other isolation points and mitigation methods are potentially available, but they are not credited due to the limited guidance that is available. The reliability of flood mitigation could be improved by developing procedures to direct specific actions for specific flood events (SAMA 9).
2FPXV-2FP058-K--	7.43E-04	1.031	L.O. MANUAL VALVE 2FP058 FTC	About 97% of the contributors including this event are attributable to a single cutset in which a fire protection pipe breaks in the reactor building and 2FP058 fails to close. Other isolation points and mitigation methods are potentially available, but they are not credited due to the limited guidance that is available. The reliability of flood mitigation could be improved by developing procedures to direct specific actions for specific flood events (SAMA 9).
RCVSEQ-ATW1-032	1.00E+00	1.031	ACCIDENT SEQUENCE ATW1-032 MARKER	Over 80% of this sequence is related to one cutset in which the failure to bypass the MSIV isolation logic fails in conjunction with failure to terminate and prevent injection that leads to subsequent overfill. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4).
2DGFN-VY06C--X--	3.29E-03	1.031	UNIT 2 DIV 2 CSCS ROOM COOLER FAN 2VY06C FAILS TO RUN	This event fails the room cooling for the RHRSW C and D pumps, which fails RHR train B. For these fan failures, portable fans could provide temporary, alternate room cooling. Room heatup calculations would be required as part of this effort to demonstrate that the portable fans could provide adequate cooling (SAMA 16). The contributors including this event are diverse, but over 60% is related to failure to align Heater Drain makeup due to adverse RB environment related to containment venting failure (due to direct operator action failure, failure to align a support system, or vent control failures). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3). SAMA 3 is contingent on the implementation of SAMA 1.
2FWRXTDRFPS--H--	1.00E+00	1.031	HEP(REC): OPERATOR FAILS TO MANUALLY RESET LEVEL 8 TRIP OR RESTART FW	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. The HFE itself represents the failure to reset the Level 8 trip and restart the MDFW pump. In over 80% of the cases, the HFE is combined with failures to start SPC and to vent containment. A potential means of reducing risk for these scenarios would be to automate SPC initiation on high suppression

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				pool temperature in non-LOCA scenarios (SAMA 2). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3). SAMA 3 is contingent on the implementation of SAMA 1.
2VYFNSEVY03CBX--	3.29E-03	1.03	VY SE CORNER ROOM (RHR B & C) COOLING FAN 2VY03C FAILS TO RUN	The RHR pump motors depend on the ECCS Equipment Area Ventilation System (VY) to maintain pump cubicle temperatures within qualification limits. Previous LSCS evaluations could not demonstrate that portable fans would provide adequate cooling for the RB corner rooms when the normal cooling system failed; therefore, portable cooling equipment is not proposed here. Over 60% of the contribution is associated with loss of injection capability caused by failure of venting support systems or the failure of the vent path. However, the reliable hard pipe containment vent will reduce support system dependencies that contribute to the failure scenarios including these contributors and the implementation of SAMA 1 will mitigate many of the contributors (SAMA 1). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3). SAMA 3 is contingent on the implementation of SAMA 1.
2RHMV-BREAK--F--	9.50E-01	1.03	MOV FAILS TO ISOLATE WITH OR WITHOUT OPERATOR ACTION	The event represents the isolation failure probability of the MOV that failed as part of the ISLOCA initiating event (in the RHR and LPCS systems). Failure to isolate leads directly to core damage due to lack of a long term inventory makeup source. A potential means of providing an indefinite source of RPV makeup would

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				be to tie the LPCS system to the RHRSW system and use the RHRSW pumps to provide injection flow to the RPV (SAMA 15).
RCVSEQ-ILOC-009	1.00E+00	1.03	ACCIDENT SEQUENCE ILOC-009 MARKER	This sequence is completely tied to event 2RHMV-BREAK--F-- and the same disposition is applicable.
2FPRXALGNFPSAH--	1.00E+00	1.029	HEP(REC): OPERATOR FAILS TO ALIGN FPS FOLLOWING CONTAINMENT VENT OR FAILURE	This event is an operator action marker that is used in cutsets where the associated HFE (containment venting) is combined with other HFEs. The results show that essentially all of the cutsets that include this HFE also include the HFE for initiating SPC and the JHEPs for these events are at the lowest allowable JHEP value. The implication is that the heat removal function is already highly reliable and that current HRA methods cannot reliably assess the failure probabilities of the contributing JHEPs. Because of this, the benefit of changes to reduce these contributors further would be questionable, but eliminating the requirement for the operators to perform these tasks is mathematical means of demonstrating a reduction in risk. Potential means of accomplishing this goal would be to either automate SPC initiation on high suppression pool temperature (SAMA 2) or by installing a rupture disk in parallel with the remotely controlled hard pipe vent path (SAMA 3).
%LOOP	1.07E-02	1.029	LOSS OF OFF-SITE POWER INITIATING EVENT	Over 70% of the LOOP contribution is related to water hammer-LOCA scenarios resulting from the start of RHR without first properly filling and venting the system. For scenarios in which a LOOP occurs when RHR is in operation (for SPC, generally), the piping will drain to the suppression pool and the lines must be re-filled before restarting the pump to prevent water hammer. The independent HEP for this action is conservatively quantified as 2.5E-02. The action is not time stressed given that the available diagnosis time is over 3 hours

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				and the main contributor to the HEP is the execution component. The HRA for the fill and vent action includes some steps that would not be performed in an accident scenario (those that require drywell entry) and it does not credit a check of the RHR discharge pressure alarm to identify fill and vent failures. This is a proceduralized check that would identify conditions in which the fill and vent process was performed incorrectly. If this check were to be credited, the independent HEP would be reduced by over an order of magnitude and because this HEP is the lead HEP in the dependent action assessments, the JHEPs would be similarly be reduced. These events are not considered to be significant contributors and no SAMAs are suggested.
RCVSEQ-GTR-058	1.00E+00	1.029	ACCIDENT SEQUENCE GTR-058 MARKER	This sequence is for loss of injection and high pressure core melt scenarios, which are dominated by DC bus and battery charger failures. These failures could be mitigated by providing a portable DC source and a means of connecting it to ESF DC distribution panel 1(2)11Y to support RCIC operation and long term RPV depressurization and with FPS injection (SAMA 14).
BWTOPWTHXSTBYH--	1.00E+00	1.027	HEP: OP FAILS TO ALIGN STANDBY TBCCW HX TRAIN	This event is an operator action marker that is used in cutsets where the associated HFE (align standby TBCCW Hx) is combined with other HFEs. About 80% of the contributors including this event are related to the generation of a LOCA signal on high DW pressure when an actual LOCA does not exist. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up water hammer events at LSCS (SAMA 7). Review of the cutsets also shows that almost all of those cases also include the HFE for failing to

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				isolate the water hammer LOCA (in the form of JHEPs). However, the independent HEP for this action is low (2.3E-3) and is driven by the time available for response, so changes to training or plant procedures would not have a meaningful impact on the reliability of the action and no additional SAMAs are suggested.
2ADRXOVERFL-EH--	1.00E+00	1.027	HEP(REC): OPERATOR FAILS TO PREVENT RPV OVERFILL (DEPRESS/FW/EARLY LEVEL CONTROL	Over 92% of the contributors including this event (terminated and prevent injection) are related to one cutset that also includes failure to bypass the MSIV low level isolation logic as part of a joint HEP. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4).
2RX--MS-AD-32H--	3.90E-02	1.027	2MSOPMSIVINLKH-- 2ADOPOVERFL-EH--	This is the joint HEP representing the failure to bypass the MSIV low level isolation logic in conjunction with failure to terminate and prevent injection that leads to subsequent overfill. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4).
RCVSEQ-GTR-028	1.00E+00	1.027	ACCIDENT SEQUENCE GTR-028 MARKER	This event is a sequence marker representing scenarios where injection is provided by HPCS after FW failure, but depressurization, SPC and venting fail. The SPC initiation action is very reliable and for almost all of the contributors including this event, operator action dependence issues would prevent any SAMAs requiring human action from reducing risk in a meaningful way. For most of the contributors, the total human error probability is either at or very close to the lowest allowable JHEP value. A potential means of reducing risk for these scenarios would be to automate SPC initiation on high suppression pool temperature in non-LOCA scenarios (SAMA 2). Most scenarios with SPC initiation failure also include the failure to vent containment, which represents the remaining means of containment heat removal. This leads to containment failure and an adverse environment in the reactor building that fails ECCS equipment. Currently, venting containment will also lead to an adverse reactor building environment; however, the hard pipe event will prevent the release of containment atmosphere into the RB when venting (SAMA 1). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3).
2CVSYVNT-ATWSF--	1.00E+00	1.027	CONTAINMENT VENT CONSERVATIVELY NOT CREDITED FOR ATWS	The containment vent path is not credited for ATWS events due to the potential for the vent path to fail and create adverse conditions in the reactor building. The reliable containment hard pipe vent would provide a

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				viable vent path for non-ATWS scenarios, but it is not designed to remove ATWS heat loads. Increasing the capacity of the reliable containment hard pipe vent would provide an additional means of containment heat removal in ATWS scenarios (SAMA 17). Other means of improving the reliability of the mitigating functions include automating SBLC initiation (SAMA 5) and installing a keylock switch for the MSIV low level isolation bypass (SAMA 4).
OSPR7HR-SW	2.80E-01	1.026	FAILURE TO RECOVER OSP WITHIN 7 HOURS (SEVERE WEATHER LOOP EVENT)	The contributors to long term LOOP events are diverse, but a means of mitigating these scenarios is to provide a portable 480V AC generator to supply a battery charger for SRV support (SAMA 8). In conjunction with the installation of SAMA 1 for reliable heat removal, ensuring SRV operation would allow the diesel fire pumps to provide low pressure RPV makeup.
2WTHE2WT01AA-PYR	5.24E-03	1.025	WT HX 2WT01AA FAILS DUE TO PLUGGING (YEARLY)	This event is a heat exchanger plugging event that leads to an initiating event that results in a high DW pressure signal when combined with other failures. Over 75% are related to water hammer induced LOCAs related to the generation of a LOCA signal when a LOCA condition does not exist. When RHR SPC is placed in service in response to certain transient events that lead to a high DW pressure signal (LOCA signal), the discharge line can drain to the suppression pool in the ~45 seconds between RHR pump load shed and the time it is reloaded on the bus, which sets up a water hammer condition. Modification of the LOCA signal logic to require both high DW pressure AND low RPV water level for initiation could prevent the scenarios that set up these water hammer events at LSCS (SAMA 7).
2SLOP-LVLCTRLH--	2.70E-01	1.025	HEP: OPERATOR FAILS TO LOWER LEVEL EARLY	Level and power control actions are tied together in ATWS scenarios. The limited time available for

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
			(ATWS)	response is the dominant performance shaping factor (PSF) controlling the relatively large level control HEP. Automating SBLC initiation (SAMA 5) is a potential means of improving the reliability of the SBLC injection function. Failure to bypass the low level MSIV isolation logic is also a contributor, which could be reduced by the installation of a keylock switch for logic bypass. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4). The installation of an automatic ATWS level control system that reduces level to just above -129 inches, inhibits ADS, and performs the "terminate and prevent" step (to disallow other non-feedwater RPV injection) could improve the reliability of the level reduction action and provide additional time for the operators to perform other required actions (SAMA 21).
RCVSEQ-DLOP-030	1.00E+00	1.024	ACCIDENT SEQUENCE DLOP-030 MARKER	These are SBO sequences in which RCIC operates until battery depletion at about 7 hours. The contributors to long term LOOP events are diverse, but a means of mitigating these scenarios is to provide a portable 480V AC generator to supply a battery charger for SRV support (SAMA 8). In conjunction with the installation of SAMA 1 for reliable heat removal, ensuring SRV operation would allow the diesel fire pumps to provide low pressure RPV makeup.
%MS	1.01E+00	1.024	MANUAL SHUTDOWN INITIATING EVENT	This event is an initiating event for manual shutdown. The top contributors for manual shutdown events are related to adverse RB conditions caused by venting/duct rupture or by containment failure after venting failure

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				(over 73%). Over 50% of the total manual shutdown contributors include failure to initiate SPC. LSCS is committed to installing a hard pipe vent, which will essentially eliminate the adverse environment condition in the RB after venting. Because this modification has not yet been implemented and is not reflected in the model or record, it has been designated as SAMA 1 for completeness. While already reliable, automating the initiation of SPC could further improve the reliability of the containment heat removal function (SAMA 2). Installation of a rupture disk in parallel with the normal hard pipe vent path could reduce the contribution from vent failures (SAMA 3).
%TI	2.16E-02	1.023	INADVERTENTLY OPEN RELIEF VALVE INITIATING EVENT	In over 70% of the IORV scenarios, the SRV successfully recloses on reduced pressure. About half of the %TI contribution is related to the failure to initiate SPC and containment venting. A potential means of reducing risk for these scenarios would be to automate SPC initiation on high suppression pool temperature in non-LOCA scenarios (SAMA 2). Most scenarios with SPC initiation failure also include the failure to vent containment, which represents the remaining means of containment heat removal. This leads to containment failure and an adverse environment in containment that fails ECCS equipment. Currently, venting containment will fail also lead to an adverse containment environment; however, the hard pipe vent will prevent the release of containment atmosphere into the RB when venting (SAMA 1). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3).

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
RCVSEQ-ATW1-040	1.00E+00	1.022	ACCIDENT SEQUENCE ATW1-040 MARKER	These sequences are for mitigated ATWS events with high pressure core melt. Over 40% of the contributors are related to the failure to close the turbine driven reactor driven feedwater pump (TDRFP) discharge MOVs (leading to loss of condensate/FW). The action itself is for closing the TDRFP discharge valves in time to prevent RPV overfill or hotwell depletion. The flow control for these pumps is provided by pump speed control rather than regulating valve and when the pumps are tripped, the flowpath remains open. When reactor pressure is reduced, flow from the condensate pumps or heater drain system can flow in an uncontrolled manner into the RPV. The frequency of these contributors could be reduced by changing the logic to auto close the TDRFP discharge valves when the pumps are tripped or are not running (SAMA 10). Another means of mitigating these sequences would be to provide an additional means of high pressure injection in an ATWS by installing cross-tie between HPCS and the FW injection line (SAMA 12).
2DGPMCSDG2A--M--	3.10E-03	1.022	DG2A COOLING WATER PUMP 2DG01P TRAIN MUA	About 80% of the contributors including this event are loss of containment heat removal cases, most of which lead to an adverse environment in the RB due to containment failure or vent duct failure. The hard pipe vent will prevent the release of containment atmosphere into the RB when venting (SAMA 1). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3).
2RHSYOPERATEB---	2.50E-02	1.021	RH TRAIN B IS IN OPERATION PRIOR TO A LOOP / DLOOP EVENT	These events represent the probability that RHR is in operation at the time of the initiating event and are related to water hammer-LOCA scenarios resulting from

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				the start of RHR without first properly filling and venting the system. For scenarios in which a initiating event occurs when RHR is in operation (for SPC, generally), the piping will drain to the suppression pool and the lines must be re-filled before restarting the pump to prevent water hammer. The independent HEP for fill and vent is conservatively quantified as 2.5E-02. The action is not time stressed given that the available diagnosis time is over 3 hours and the main contributor to the HEP is the execution component. The HRA for the fill and vent action includes some steps that would not be performed in an accident scenario (those that require drywell entry) and it does not credit a check of the RHR discharge pressure alarm to identify fill and vent failures. This is a proceduralized check that would identify conditions in which the fill and vent process was performed incorrectly. If this check were to be credited, the independent HEP would be reduced by over an order of magnitude and because this HEP is the lead HEP in the dependent action assessments, the JHEPs would be similarly be reduced. These events are not considered to be significant contributors and no SAMAs are suggested.
2RHSYOPERATEA---	2.50E-02	1.021	RH TRAIN A IS IN OPERATION PRIOR TO A LOOP / DLOOP EVENT	Same as for 2RHSYOPERATEB---.
2RX-FWADRHCV6H--	5.00E-07	1.021	2FWOPMOV10AB-H-- 2ADOP-INHIBITH-- 2ADOP-TRANS--H-- 2RHOPSPCINIT-H-- 2CVOPVEN	This is the joint HEP representing the failure of multiple operator actions, including SPC initiation. Because the value of this joint HEP is set at the lowest allowable JHEP value, SAMAs that require additional operator actions would not have a measurable impact on risk. A potential means of reducing risk for these scenarios would be to automate SPC initiation on high suppression

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				pool temperature in non-LOCA scenarios (SAMA 2).
RCVSEQ-LOOP-041	1.00E+00	1.02	ACCIDENT SEQUENCE LOOP-041 MARKER	This event is an accident sequence marker for LOOP events with early injection failure. Over 85% of the contribution is related to water hammer-LOCA scenarios resulting from the start of RHR without first properly filling and venting the system (all LOOP events). For scenarios in which a LOOP occurs when RHR is in operation (for SPC, generally), the piping will drain to the suppression pool and the lines must be re-filled before restarting the pump to prevent water hammer. The independent HEP for this action is conservatively quantified as 2.5E-02. The action is not time stressed given that the available diagnosis time is over 3 hours and the main contributor to the HEP is the execution component. The HRA for the fill and vent action includes some steps that would not be performed in an accident scenario (those that require drywell entry) and it does not credit a check of the RHR discharge pressure alarm to identify fill and vent failures. This is a proceduralized check that would identify conditions in which the fill and vent process was performed incorrectly. If this check were to be credited, the independent HEP would be reduced by over an order of magnitude and because this HEP is the lead HEP in the dependent action assessments, the JHEPs would be similarly be reduced. These events are not considered to be significant contributors and no SAMAs are suggested.
2SLRX-IN-ERLYH--	1.00E+00	1.02	HEP(REC): OPERATOR FAILS TO INITIATE SBLC EARLY	This event is an operator action marker that is used in cutsets where the associated HFE (SBLC initiation) is combined with other HFEs. In most cases, it is combined with the failure to bypass the low level MSIV isolation logic. Installing a keylock MSIV low level

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4). Automating SBLC system initiation could also reduce these contributors (SAMA 5).
RCVSEQ-ATW1-036	1.00E+00	1.02	ACCIDENT SEQUENCE ATW1-036 MARKER	This event is an accident sequence marker for loss of condenser ATWS events with failures of ADS inhibit and early SBLC injection/level control. Operator failures to inject SBLC and to bypass low level MSIV isolation logic are both large contributors at about 75% each. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4). Automating SBLC system initiation could also reduce these contributors (SAMA 5).
%TDCA	5.70E-04	1.02	LOSS OF 125 VDC BUS 2A INITIATING EVENT	This is an initiating event representing the loss of the "A" train ESF DC bus, which essentially eliminates an entire division of equipment. The failures contributing to core

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				damage in conjunction with this event are diverse and the most effective means of mitigating the scenario would be to bypass the bus failure. This could be accomplished by providing a portable generator with DC output that could be connected to distribution panel 1(2)11Y. This would support RCIC and SRV operation, which if combined with SAMA 1, would provide a long term means of providing RPV makeup via FPS injection.
1DGFN-VY05C--X--	3.29E-03	1.02	UNIT 1 DIV 1 CSCS ROOM COOLER FAN 1VY05C FAIL TO RUN	Failure of cooler fan 1VY05C results in failure of the 0DGCWP pump, which supplies cooling water to the 2A RHR pump room coolers and leads to failure of the 2A RHR pump. Installation of a portable fan for temporary cooling could prevent failure of the 0DGCWP pump and subsequent RHR pump failure. Room heatup calculations would be required as part of this effort to demonstrate that the portable fans could provide adequate cooling (SAMA 16).
2ACSYLOOPNLOCA--	2.40E-03	1.019	COND PROB OF A LOOP GIVEN NO LOCA SIGNAL	For consequential LOOP events without a LOCA, the contributors to core damage are diverse. SBO event with failure of injection comprise about half of the contribution and water hammer LOCAs contribute to about 30% of the total. Early injection capability could be enhanced for the SBO cases if a hard pipe connection were installed between the Fire Protection and Feedwater systems. If a permanent connection between the systems is undesirable, a short, flexible connecting hose could potentially be maintained out of the flowpath provided that rapid alignment could be demonstrated (SAMA 18). As described for sequence marker RCVSEQ-LOOP-041, the HEP for fill and vent does not credit available checking mechanisms, which, if credited, would significantly reduce the water hammer contribution and no SAMAs are required to address

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				those scenarios.
2ADOP-FW--AT-H--	2.70E-02	1.019	HEP: OPERATOR FAILS TO MANUALLY DEPRESSURIZE THE RPV - ATWS (FW AVAILABLE)	This event represents the failure to depressurize the RPV in ATWS scenarios after initially inhibiting depressurization. In these cases, there is an automatic depressurization function, but it has been successfully bypassed as part of accident mitigation. In over 67% of these cases, this action is required due to the failure to bypass the low level MSIV isolation bypass logic. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4).
2RX-FWRHCVF15H--	5.00E-07	1.019	2FWOPMOV10AB-H-- 2RHOPSPCINIT-H-- 2CVOPVENT----H-- 2RHOPSPCLATE-H-- 2FPOPALG	This event is a joint HEP that addresses several actions, including SPC initiation and containment venting. The joint HEP is at the lowest allowable JHEP value, implying that operator action dependence issues would prevent any SAMAs requiring human action from reducing risk in a meaningful way. A potential means of reducing risk for these scenarios would be to automate SPC initiation on high suppression pool temperature in non-LOCA scenarios (SAMA 2). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3).
2RX-FWRHCVF35H--	5.00E-07	1.019	2FWOPMOV10AB-H--	This event is a joint HEP that addresses several actions,

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
			2RHOPSPCINIT-H-- 2CVOPVENT----H-- 2RHOPSPCLATE-H-- BFPOP-DF	including SPC initiation and containment venting. The joint HEP is at the lowest allowable JHEP value, implying that operator action dependence issues would prevent any SAMAs requiring human action from reducing risk in a meaningful way. A potential means of reducing risk for these scenarios would be to automate SPC initiation on high suppression pool temperature in non-LOCA scenarios (SAMA 2). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3).
RCVSEQ-ATW1-034	1.00E+00	1.018	ACCIDENT SEQUENCE ATW1-034 MARKER	This event is an accident sequence marker for ATWS scenarios with early SBLC or level control failures. In about 70% of the cases, the operators fail to bypass the low level MSIV isolation logic. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4). Another contributor, at about 25%, is the failure to initiate SBLC. Automating system initiation could reduce these contributors (SAMA 5).
2RX--LVL-SL-2H--	6.50E-02	1.018	2SLOP-LVLCTRLH-- 2SLOP-IN-LATEH--	This event is a joint HEP that addresses failure to control level early and to inject SBLC late. Automating SBLC injection would mitigate these scenarios (SAMA 5). The installation of an automatic ATWS level control system

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				that reduces level to just above -129 inches, inhibits ADS, and performs the "terminate and prevent" step (to disallow other non-feedwater RPV injection) could improve the reliability of the level reduction action and provide additional time for the operators to perform other required actions (SAMA 21).
DLOOP-IE-GR	3.72E-01	1.017	COND. PROB. DLOOP DUE TO GRID RELATED EVENT	This event represents the prob. that a DLOOP event is related to a grid failure. About 40% of the contribution is related to water hammer-LOCAs resulting from the start of RHR without first properly filling and venting the system. For scenarios in which a LOOP occurs when RHR is in operation (for SPC, generally), the piping will drain to the SP and the lines must be re-filled before restarting the pump to prevent water hammer. The HEP for this action is conservatively quantified as 2.5E-02. The HFE is not time stressed given that the available diagnosis time is over 3 hours and the main contributor to the HEP is the execution component. The HRA for the fill and vent action includes some steps that would not be performed in an accident scenario (those that require drywell entry) and it does not credit a check of the RHR discharge press. alarm to identify errors. This is a proceduralized check that would identify fill and vent failures. If this check were to be credited, the HEP would be reduced by over an order of magnitude and because this HEP is the lead HEP in the dependent action assessments, the JHEPs would be similarly be reduced. These events are not considered to be significant contributors and no SAMAs are suggested. A majority of the remaining contributors are long term SBO events. These could be addressed by providing a portable generator to support the battery chargers (SAMA 8) in combination with the hard pipe vent (SAMA 1).

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
2PLASRECLOSE-F--	8.50E-01	1.017	SRVs SUCCESSFULLY RECLOSED ON REDUCED PRESSURE	About 58% of the contribution associated with IORV events in which the SRV recloses on reduced pressure include failure of the operator to initiate SPC. A potential means of reducing risk for these scenarios would be to automate SPC initiation on high suppression pool temperature in non-LOCA scenarios (SAMA 2). Most scenarios with SPC initiation failure also include the failure to vent containment, which represents the remaining means of containment heat removal. This leads to containment failure and an adverse environment in the reactor building that fails ECCS equipment. Currently, venting containment will also lead to an adverse reactor building environment; however, the hard pipe vent will prevent the release of containment atmosphere into the RB when venting (SAMA 1). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3).
OSPR30MIN-SW	7.73E-01	1.017	FAILURE TO RECOVER OSP WITHIN 30 MIN. (SEVERE WEATHER LOOP EVENT)	This event represents the probability of failing to recover offsite power for a severe weather related LOOP in 30 minutes. About 70% of the contribution is related to water hammer-LOCAs resulting from the start of RHR without first properly filling and venting the system. For scenarios in which a LOOP occurs when RHR is in operation (for SPC, generally), the piping will drain to the SP and the lines must be re-filled before restarting the pump to prevent water hammer. The HEP for this action is conservatively quantified as 2.5E-02. The HFE is not time stressed given that the available diagnosis time is over 3 hours and the main contributor to the HEP is the execution component. The HRA for the fill and vent action includes some steps that would not be performed

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				in an accident scenario (those that require drywell entry) and it does not credit a check of the RHR discharge press. alarm to identify errors. This is a proceduralized check that would identify fill and vent failures. If this check were to be credited, the HEP would be reduced by over an order of magnitude and because this HEP is the lead HEP in the dependent action assessments, the JHEPs would be similarly be reduced. These events are not considered to be significant contributors and no SAMAs are suggested.
2RX--RH-CV--3H--	1.50E-06	1.017	2RHOPSPCINIT-H-- 2CVOPVENT----H-- 2RHOPSPCLATE-H--	This event is a joint HEP that addresses SPC initiation and containment venting. The joint HEP is near the lowest allowable JHEP value, implying that operator action dependence issues would prevent any SAMAs requiring human action from reducing risk in a meaningful way. A potential means of reducing risk for these scenarios would be to automate SPC initiation on high suppression pool temperature in non-LOCA scenarios (SAMA 2). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3).
2HDOP-HD-ERLYH--	1.00E+00	1.016	HEP: OPERATOR FAILS TO ALIGN HEATER DRAIN FOR INJECTION (EARLY TIME FRAME)	This event represents the HEP for aligning the heater drain pumps for early injection. The HEP is 1.0 due to the lengthy time required for alignment. Early injection capability could be enhanced for this scenario as well as for SBO cases if a hard pipe connection were installed between the Fire Protection and Feedwater systems. If a permanent connection between the systems is undesirable, a short, flexible connecting hose could potentially be maintained out of the flowpath provided that rapid alignment could be demonstrated (SAMA 18).

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
2VYFNNWVY01--X--	3.29E-03	1.016	VY NW CORNER ROOM (RHR A) COOLING FAN 2VY01C FAILS TO RUN	Loss of the cooling fan in the northwest (NW) corner room results in the loss of RHR pump "A" due to overheating. Previous LSCS evaluations could not demonstrate that portable fans would provide adequate cooling for the RB corner rooms when the normal cooling system failed; therefore, portable cooling equipment is not proposed here. Over 60% of the contribution is associated with loss of injection capability caused by failure of venting support systems or the failure of the vent path. However, the reliable hard pipe containment vent will reduce support system dependencies that contribute to the failure scenarios including these contributors and the implementation of SAMA 1 will mitigate many of the contributors (SAMA 1). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3). SAMA 3 is contingent on the implementation of SAMA 1.
2DGFN-VY05C--X--	3.29E-03	1.016	UNIT 2 DIV 1 CSCS ROOM COOLER FAN 2VY05C FAIL TO RUN	Failure of cooler fan 2VY05C results in failure of the 2A and 2B RHRSW pumps, which supply cooling water to the 2A RHR pump and the 2A RHR heat exchanger. Installation of a portable fan for temporary cooling could prevent failure of the 2A and 2B RHRSW pumps and subsequent RHR pump failure (SAMA 16).
2RHPME12C002BM--	2.97E-03	1.016	RH TRAIN 2B (2E12-C002B) MUA	This event represents the maintenance unavailability of the RHR 2B pump. The contributors to other RHR train failures are diverse, but venting failures (and subsequent containment failures that lead to loss of RPV makeup) are mostly due to support system unavailability, which will be addressed by the reliable containment hard pipe vent (SAMA 1). Other contributors include cases in

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				which containment venting is successful, but vent duct failure leads to adverse conditions in the RB and subsequent injection failure. These cases would also be mitigated by the reliable containment hard pipe vent.
%TDCAB	3.42E-07	1.016	LOSS OF 125 VDC BUS 2A AND 2B INITIATING EVENT	About 85% of the contribution for the loss of DC bus 2A and 2B initiating event is related to the case in which the 125V HPCS DC bus also fails (bus 213). In these cases, there is no 125V DC power available to support either injection or RPV depressurization. These failures could be mitigated by providing a portable DC source and a means of connecting it to ESF DC distribution panel 1(2)11Y to support RCIC operation and long term RPV depressurization and with FPS injection (SAMA 14).
2DCRX2A2A2B--H--	7.10E-01	1.016	HEP: OP FAILS TO RCVR BATT BUS 2A GIVEN LOSS OF BUS 2A AND 2B IE	This event is related to the initiating event %TDCAB and SAMA 14 is also applicable.
2DCRX2B2A2B--H--	7.10E-01	1.016	HEP: OP FAILS TO RCVR BATT BUS 2B GIVEN LOSS OF BUS 2A AND 2B IE	This event is related to the initiating event %TDCAB and SAMA 14 is also applicable.
2FPOPMANTRIP1H--	4.10E-01	1.015	HEP: OPERATOR FAILS TO TRIP FPS FOR FPS BREAK (SHORT TIME FRAME)	Over 93% of the contribution associated with the failure to trip the FPS pumps in the short term comes from a cutset in which it is combined with long term FPS trip failure (where over 13 hours are available for diagnosis). For such an extended time available for response, the mitigation action is highly reliable and it is inconceivable that the FPS pumps would not be tripped and the SW system connection valves isolated. SAMAs that require manual actions to isolate or terminate the flood would have a limited benefit for these contributors due to operator dependence issues. The reliability of the FPS flood mitigation action, could, however, be improved by simplifying the process. This could be accomplished by

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				providing a means of tripping the FPS diesel fire pumps from the MCR combined with flood zone specific procedures to direct remote isolation of FPS valves (SAMA 11).
2ADRX-ADS-AT-H--	1.00E+00	1.015	HEP(REC): OPERATOR FAILS TO MANUALLY DEPRESSURIZE THE RPV-ATWS (NO FW AVAIL)	This event is an operator action marker that is used in cutsets where the associated HFE (manual depressurization) is combined with other HFEs. This action is required because the ADS function is inhibited for ATWS. The independent HEP for depressurization is dominated by the ASEP cognitive contribution and is based on the short response time available. About 75% of the contributors including this event also include failure to bypass the MSIV low level interlock. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4).
2CD--2CD01AMS---	3.00E-02	1.015	COND PROBY MAN SHTDWN REQD FOR MAIN CONDENSER 2CD01A MAINT	The top contributors including this event are related to adverse conditions caused by failure to vent or venting (over 75%) and HFEs related to the alignment of SPC (over 50%). In conjunction with the hard pipe vent, a parallel, passive vent path could provide a means of ensuring that the containment failure occurs through a rupture disk with a scrubbed path from the wetwell (SAMA 3). While already reliable, automating the initiation of SPC could further improve the reliability of

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				the containment heat removal function (SAMA 2).
2ADRXOVERFL-LH--	1.00E+00	1.015	HEP(REC): OPERATOR FAILS TO PREVENT RPV OVERFILL (DEPRESS/FW/LATE LEVEL CONTROL)	About 70% of the contributors including this event (terminated and prevent injection) are related to one cutset that also includes failure to bypass the MSIV low level isolation logic as part of a joint HEP. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4).
%ISLOCA-SDC	3.80E-08	1.014	SDC SUCTION LINE ISLOCA	Failure to isolate the pathway is the dominant contributor for this ISLOCA event, which leads directly to core damage due to lack of a long term inventory makeup source. A potential means of providing an indefinite source of RPV makeup would be to tie the LPCS system to the RHRSW system and use the RHRSW pumps to provide injection flow to the RPV (SAMA 15).
BFPOP-DFPENV-H--	1.00E-01	1.014	HEP: OP FAILS TO ALIGN DFP DUE TO ADVERSE ENV IN TB (VENT TO RB OR CNTNMT FAIL)	This event is the independent HEP for the alignment of DFP injection when the RB conditions are adverse due to containment failure or vent path failure. These cases will be addressed by the reliable containment hard pipe vent. SAMA 1 will provide a vent path capable of withstanding the pressures associated with containment venting. For the cases in which venting fails, it is generally due to support system failure. SAMA 1 eliminates the support system dependencies that currently exist for containment venting. No SAMAs

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				required.
2FPOPMANTRIP4H--	8.80E-04	1.014	HEP: OPERATOR FAILS TO TRIP FPS GIVEN FAILURE OF SHORT TIME FRAME (COND PROB)	All of the contribution associated with the failure to trip the FPS pumps in the short term comes from a cutset in which it is combined with long term FPS trip failure (where over 13 hours are available for diagnosis). For such an extended time available for response, the mitigation action is highly reliable and it is inconceivable that the FPS pumps would not be tripped and the SW system connection valves isolated. SAMAs that require manual actions to isolate or terminate the flood would have a limited benefit for these contributors due to operator dependence issues. The reliability of the FPS flood mitigation action, could, however, be improved by simplifying the process. This could be accomplished by providing a means of tripping the FPS diesel fire pumps from the MCR combined with flood zone specific procedures to direct remote isolation of FPS valves (SAMA 11).
BDGPMCSTRN0A-M--	3.10E-03	1.014	DG0 COOLING WATER PUMP 0DG01P TRAIN MUA	This event is related to loss of decay heat removal scenarios. The 0DGCWP pump supplies cooling water to the 2A RHR pump room coolers and its unavailability leads to failure of the 2A RHR pump. Previous LSCS evaluations could not demonstrate that portable fans would provide adequate cooling for the RB corner rooms when the normal cooling system failed; therefore, portable cooling equipment is not proposed here. Over 70% of the contribution is associated with loss of injection capability caused by failure of venting support systems or the failure of the vent path. However, the reliable hard pipe containment vent will reduce support system dependencies that contribute to the failure scenarios including these contributors and the implementation of SAMA 1 will mitigate many of the

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				contributors (SAMA 1). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3). SAMA 3 is contingent on the implementation of SAMA 1.
2ACRX-AC-CBS-H--	1.00E+00	1.014	HEP(REC): OPERATOR FAILS TO CLOSE BREAKER TO 4KV BUS AFTER OFFSITE AC POWER RECO	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. In about 50% of the contributors, the JHEP is driven by the chronologically first HEP (DG 0 alignment), which is conservatively based on a timing scenario in which there is no RPV makeup; however, in most of the cases in which the JHEP is applied, HPCS is available and there would be many hours available for DG 0 alignment rather than 30 minutes. The treatment is conservative and if the time window reflected HPCS availability, these combinations would not be significant and no SAMAs are required. In the other case, the HEP is combined with failure to initiate SPC, which could be addressed by automating SPC initiation in non-LOCA scenarios (SAMA 2).
RCVCL-1D	1.00E+00	1.014	ACCIDENT CLASS ID MARKER	This event is an accident class marker for loss of RPV makeup at high pressure scenarios and does not represent any specific failure itself. Many of these cases are loss of DC scenarios, most of which are related to 125V DC bus failures. These failures could be mitigated by providing a portable DC source and a means of connecting it to ESF DC distribution panel 1(2)11Y to support RCIC operation and long term RPV depressurization and with FPS injection (SAMA 14).
2ADOPRPVLEVELH--	1.80E-02	1.013	HEP: OPERATOR CONTROLS RPV LEVEL TOO LOW (LOW	This is the independent HFE for failing to maintain level high enough in ATWS events, although about 65% of the combination is from its combination with failure to

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
			PRESSURE - ATWS)	bypass the low level MSIV isolation logic. A JHEP was not used in the model for the action pair because the independent combination yields essentially the same results as the JHEP; however, installing a keylock bypass on the low level MSIV isolation logic is a potential means of reducing the frequency of these scenarios. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4).
OSPR30MIN-SWYD	5.95E-01	1.013	FAILURE TO RECOVER OSP WITHIN 30 MIN. (SWYD CENTERED EVENT)	The failure to recover offsite power in 30 minutes, as represented by this event, is important in induced LOCA scenarios. For scenarios in which a LOOP occurs when RHR is in operation (for SPC, generally), the piping will drain to the suppression pool and the lines must be re-filled before restarting the pump to prevent water hammer (about 80% of the contribution). The independent HEP for this action is conservatively quantified as 2.5E-02. The action is not time stressed given that the available diagnosis time is over 3 hours and the main contributor to the HEP is the execution component. The HRA for the fill and vent action includes some steps that would not be performed in an accident scenario (those that require drywell entry) and it does not credit a check of the RHR discharge pressure alarm to identify fill and vent failures. This is a proceduralized check that would identify conditions in which the fill and vent process was performed incorrectly. If this check were to be credited, the independent HEP would be reduced by over an order of magnitude and because this HEP is the lead HEP in the

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				dependent action assessments, the JHEPs would be similarly be reduced. These events are not considered to be significant contributors and no SAMAs are suggested.
RCVSEQ-ATW1-041	1.00E+00	1.013	ACCIDENT SEQUENCE ATW1-041 MARKER	This event is an accident sequence marker for ATWS scenarios and does not represent any specific failure itself. About 65% of the contribution is related to the failure to close the turbine driven feedwater pump discharge valves in time to prevent RPV overfill or hotwell depletion. The flow control for these pumps is provided by pump speed control rather than regulating valve and when the pumps are tripped, the flowpath remains open. When reactor pressure is reduced, flow from the condensate pumps or heater drain system can flow in an uncontrolled manner into the RPV. The HEP is driven by the time reliability component and the execution component for two valve closures, which presents limited opportunity for improvement. The frequency of these contributors could be reduced by changing the logic to auto close the TDRFP discharge valves when the pumps are tripped or are not running (SAMA 10).
2DCBSCOND213CF--	2.00E-01	1.013	COND PROB OF FAIL OF DIV 3 125 VDC BUS GIVEN LOSS OF DIVs 1 & 2 DC IE	There is one cutset that includes this event, which is a scenario initiated by loss of DC bus 2A and 2B. In these cases, there is no 125V DC power available to support either injection or RPV depressurization. These failures could be mitigated by providing a portable DC source and a means of connecting it to ESF DC distribution panel 1(2)11Y to support RCIC operation and long term RPV depressurization and with FPS injection (SAMA 14).
BDGHUCDG0---H--	8.00E-03	1.013	PRE-HEP: OPERATOR MISALIGNS 0 DG SPEED	This event is a pre-initiator HFE that results in the failure of the 0 EDG. About 80% of these cases are long term

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
			DROOP	SBOs in which high pressure injection is initially available and depressurization is available. Containment venting fails primarily due to support system unavailability and leads to the failure of RPV makeup. The reliable hard pipe containment vent will mitigate these scenarios by providing a means of venting without support systems (SAMA 1).
2CNFLMLLOCA--PCC	1.00E-04	1.013	CCF (PLUGGING) OF ECCS SUCT STRAINERS (LOCA)	For common cause failure (CCF) of the ECCS suction strainers, the implication is that the suppression pool is unavailable due to debris issues. These top contributors including this event are medium LOCA events with breaks both above and below TAF. Installing a connection from the RHRSW system on the RHR pump suction line could provide a means of back flushing the suction strainer and restoring flow (SAMA 6), but there may be time limitations that would prevent this from being successful. Providing the capability to align RHRSW to the LPCS pumps from the MCR is a means of rapidly providing alternate flow for core cooling (SAMA 19). For the dominant contributors, depressurization is available.
2HCHUF038----H--	8.00E-03	1.012	PRE-HEP: OPERATOR MISALIGNS HPCS AND LEAVES 2E22-F038 CLOSED AFTER MAINT.	The event represents a pre-initiator HFE in which the in-containment manual injection isolation valve is left closed (not recoverable in an accident scenario). In a majority of cases, the depressurization function is available, but a means of injection is not available due to lack of AC or DC power combined with other random failures. Improving the connection between the fire protection and Feedwater systems so that injection can be aligned rapidly would mitigate many of these contributors (SAMA 18).
%S2-WA	3.67E-03	1.011	INIT: SMALL BREAK LOCA - BELOW CORE INSIDE	The contributors for this small LOCA initiating event are diverse, but potential mitigating measures include SAMA

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
			DRYWELL	1 for preventing vent pathway failure and providing a rapid means of aligning RHRSW to LPCS for injection (SAMA 19).
2RHPME12C002AM--	2.97E-03	1.011	RH TRAIN 2A (2E12-C002A) MUA	For cases in which RHR train 2A is unavailable due to maintenance, most of the containment vent and vent path failures would be addressed by SAMA 1. Containment vent failure due to support system unavailability would be addressed by the capability of the reliable hard pipe vent to be operated without support systems. The failure of the vent path would be addressed by SAMA 1 because the hard pipe vent is designed to accommodate containment pressure during a vent action.
RCVSEQ-GTR-057	1.00E+00	1.011	ACCIDENT SEQUENCE GTR-057 MARKER	This event is an accident sequence marker for transient scenarios with failure of high and low pressure injection. About 50% of the contributors are related to the failure to close the TDRFP discharge MOVs (leading to loss of condensate/FW). The action itself if for closing the turbine driven feedwater pump discharge valves in time to prevent RPV overfill or hotwell depletion. The flow control for these pumps is provided by pump speed control rather than regulating valve and when the pumps are tripped, the flowpath remains open. When reactor pressure is reduced, flow from the condensate pumps or heater drain system can flow in an uncontrolled manner into the RPV. The frequency of these contributors could be reduced by changing the logic to auto close the TDRFP discharge valves when the pumps are tripped or are not running (SAMA 10). An alternative approach would be to enhance the fire protection system connection to the FW system to provide an alternate means of early injection when depressurization is possible (SAMA 18).

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
RCVSEQ-DLOP-032	1.00E+00	1.011	ACCIDENT SEQUENCE DLOP-032 MARKER	This event is an accident sequence marker for long term SBO scenarios in which RCIC initially operates but fails after battery depletion. After installation of a hardened containment vent at LSCS, a viable means of containment heat removal will be available in SBO scenarios. The diesel fire pump is a currently proceduralized injection source that can be used in an SBO, but this low pressure injection source would only be available until the SRVs close after battery depletion (RPV re-pressurization would prevent continued injection). Use of a portable generator to provide long term power to the 125 VDC battery chargers would provide a means of maintaining diesel fire pump makeup indefinitely (SAMA 8).
RCVCL-3D	1.00E+00	1.01	ACCIDENT CLASS IIID MARKER	This event is an accident class marker for large LOCA scenarios with failure of vapor suppression and does not represent any specific failure itself. The results are dominated by failures of the vacuum breakers to re-close. The existing vacuum breakers are reliable, but a potential means of reducing the frequency of these types of scenarios would be to install redundant vacuum breakers in each of the lines (SAMA 20)
2RX-SL-MS3-23H--	1.50E-02	1.01	2SLOP-IN-ERLYH-- 2MSOPMSIVINLKH-- 2SLOP-LATELVLH--	This is the joint HEP representing the failure of multiple operator actions, including failure of bypass the low level MSIV isolation logic, early SBLC initiation, and late level control. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and provide more time margin for the actions in ATWS scenarios requiring isolation bypass, thereby improving the reliability of the human control actions. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4). Automating SBLC system initiation is another means of reducing the frequency of these contributors (SAMA 5). The installation of an automatic ATWS level control system that reduces level to just above -129 inches, inhibits ADS, and performs the "terminate and prevent" step (to disallow other non-feedwater RPV injection) could improve the reliability of the level reduction action and provide additional time for the operators to perform other required actions (SAMA 21).
2MSAVMSIVTRIPF--	1.00E-02	1.01	COND PROB OF MSIV ISOL FOLLOWING A TRIP	Over 50% of the contributors associated with the conditional probability of MSIV closure after trip include a failure to initiate SPC. While already reliable, automating the initiation of SPC could further improve the reliability of the containment heat removal function (SAMA 2). There are also additional cases in which venting fails after hardware related failures of containment heat removal. In conjunction with the hard pipe vent, a parallel, passive vent path could provide a means of ensuring that the containment failure occurs through a rupture disk with a scrubbed path from the wetwell (SAMA 3).
2CN--RUPT-WWWF--	1.83E-02	1.01	WW RUPTURE BELOW WATER LINE	For the scenarios including wetwell failures below the water line, about half of the contributors include the JHEP for failing to initiate SPC and containment venting. A potential means of reducing risk for these scenarios would be to automate SPC initiation on high suppression pool temperature in non-LOCA scenarios (SAMA 2). For the other half of the contributors, the support systems required for venting are failed, which will be mitigated by implementation of SAMA 1.

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
BDGDGU1DG0---F--	5.00E-01	1.01	DIESEL GENERATOR DG0 AUTO CLOSES TO UNIT 1 (50% OF THE TIME)	This event represents the probability that the undervoltage signal will first register for Unit 1 in a DLOOP event and that DG 0 will auto align to Unit 1. In these cases, the operator must manually align DG 0 power to Unit 2. Over 96% of the contributors including this event also include failure to manually align DG 0 to Unit 2. Almost 70% of the contributors also include failure to restore offsite AC power after recovery. In these cases, containment venting for heat removal fails due to support system unavailability, which could be mitigated by SAMA 1 because of the capability to vent without support systems.
2MSOPMSIVINLKHSU	3.00E-01	1.01	HEP: OP SUCCESSFULLY BYPASSES MSIV LOW LEVEL INTERLOCK	This event represent the probability that the operators successfully bypass the low level MSIV isolation logic in an ATWS. The top contributor (~65%) is that late level control fails after this success followed by failure to initiate SBLC. The action for level control is about 1/3 cognitive and 2/3 execution failure, which is driven by the relatively large number of steps required to control the FW system. These controls are familiar to the operators and the execution error may be conservative, but a potential means of reducing these types of failures would be to automate the initial ATWS power and level control steps. The installation of an automatic ATWS level control system that reduces level to just above -129 inches, inhibits ADS, and performs the "terminate and prevent" step (to disallow other non-feedwater RPV injection) could improve the reliability of the level reduction action and provide additional time for the operators to perform other required actions (SAMA 21).
2DGDM-VY04Y--D--	1.14E-03	1.01	UNIT 2 DIV 2 CSCS ROOM COOLING DAMPER 2VY04Y FAILS TO OPEN	This damper failure in the Unit 2 CSCS Division 2 vault leads to the loss of room cooling and ultimately, the failure of the RHRSW 2C, RHRSW 2D, and 2A DGCW

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				pumps. Providing an alternate means of room cooling, such as with portable fans, could prevent failure of the equipment in the vault (SAMA 16).
2DGDM-VY05Y--K--	1.14E-03	1.01	UNIT 2 DIV 2 CSCS ROOM COOLING DAMPER 2VY05Y FAILS TO CLOSE	This damper failure in the Unit 2 CSCS Division 2 vault leads to the loss of room cooling and ultimately, the failure of the RHRSW 2C, RHRSW 2D, and 2A DGCW pumps. Providing an alternate means of room cooling, such as with portable fans, could prevent failure of the equipment in the vault (SAMA 16).
2DGDM-VY06Y--D--	1.14E-03	1.01	UNIT 2 DIV 2 CSCS ROOM COOLING DAMPER 2VY06Y FAILS TO OPEN	This damper failure in the Unit 2 CSCS Division 2 vault leads to the loss of room cooling and ultimately, the failure of the RHRSW 2C, RHRSW 2D, and 2A DGCW pumps. Providing an alternate means of room cooling, such as with portable fans, could prevent failure of the equipment in the vault (SAMA 16).

Table F.5-2a
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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
LERF	1.00E+00	3.127	PROBABILITY OF A LARGE, EARLY RELEASE (CLASS V)	This is a marker event for cutsets that result in LERF from the containment bypass sequence. Over 91% are related to event 2RHMV-BREAK--F--, which is addressed in the Level 1 importance review.
LERF-IVLERF-V	1.00E+00	3.127	LEVEL 2 LERF-V ENDSTATE	This is a recovery flag marker that is completely tied to the LERF flag. Over 91% are related to event 2RHMV-BREAK--F--, which is addressed in the Level 1 importance review.
RCVCL-5	1.00E+00	3.127	ACCIDENT CLASS V MARKER	Addressed in the Level 1 Importance Review.
2RHMV-BREAK--F--	9.50E-01	2.632	MOV FAILS TO ISOLATE WITH OR WITHOUT OPERATOR ACTION	Addressed in the Level 1 Importance Review.
2RHPPISLOCA--R--	1.00E+00	2.632	RH LOW PRESSURE PIPING RUPTURES DURING ISLOCA EVENT	Addressed in the Level 1 Importance Review.
RCVSEQ-ILOC-009	1.00E+00	2.632	ACCIDENT SEQUENCE ILOC-009 MARKER	Addressed in the Level 1 Importance Review.
%ISLOCA-SDC	3.80E-08	1.396	SDC SUCTION LINE ISLOCA	Addressed in the Level 1 Importance Review.
2NCPHNCF-----F--	1.00E+00	1.228	LARGE CONTAINMENT FAILURE CLASS IIV, IIID, OR IV	This is a marker event for large containment failure scenarios. Over 50% are related to vapor suppression failures resulting from the failure of a vacuum breaker to reclose. These events could be mitigated by installing redundant vacuum breakers in each line (SAMA 20). Another 40% are related to ATWS events, which are addressed on the Level 1 list by SAMAs 4, 5, and 21. This is generally true for all of the ATWS related events in the Level 2 importance lists. Combustible gas venting failure occurs for these cases, but the large containment failures are not linked to hydrogen detonation/deflagration, but rather to overpressurization. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure (SAMA 17).

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
2GVPHCMBSTGASF--	1.00E+00	1.182	COMBUSTIBLE GAS VENTING FAILS	About 50% of the contributors including this event are related to ATWS scenarios while most of the remaining half are related to station blackout scenarios. In ATWS cases, the containment vent capacity is not capable of keeping up with combustible gas generation while for SBO scenarios, venting is not currently possible due to lack of power for the containment vent valves. The installation of the reliable containment hard pipe vent (SAMA 1) will address support system failures for SBO cases and allow venting. For ATWS scenarios, most containment failures are related to overpressurization rather than hydrogen detonation/deflagration. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment overpressure and by providing a means of venting combustible gases (SAMA 17). Alternatively, hydrogen detonation could be prevented by the installation of hydrogen ignitors (SAMA 22).

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LSCS “High” Importance List Review

EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
2GVPH-INERT--X--	9.90E-01	1.163	CONTAINMENT INERTED; VENTING NOT REQUIRED	This event identifies scenarios in which the containment remains inerted and combustible gas venting is not required. In these cases, phenomena other than combustible gas explosions lead to containment failure. About 70% of the contribution is related to the failure of the vacuum breakers to re-close resulting in a vapor suppression failure. These failures could be mitigated by installing redundant vacuum breakers in each line (SAMA 20). The failure to arrest core melt in-vessel is associated with these same contributors. In these cases, RPV makeup is failed as a consequence of containment failure, either due to harsh reactor building environment or by injection line damage caused by containment failure. Prevention of containment failure is considered to be the most effective means of mitigating these cases and SAMA 20 is again relevant. A large portion of the remaining cases are associated with DC bus failures, which could be addressed by providing a DC generator with the capability to directly power the RCIC distribution panel (SAMA 14).
RX11	1.00E+00	1.125	FAILURE TO ARREST CORE MELT IN-VESSEL (CLASS IIIA, IIID AND IV OP=F)	This is a marker event designating the failure to terminate core melt in the RPV (i.e., the core melts through the vessel) for Class IIIA, IIID, and IV scenarios. About 90% of the contribution is related to large LOCA events in which the failure of the vacuum breakers to re-close results in a vapor suppression failure. In these cases, RPV makeup is failed as a consequence of containment failure, either due to harsh reactor building environment or by injection line damage caused by containment failure. These failures could be mitigated by installing redundant vacuum breakers in each line (SAMA 20). SAMA 15 suggests the connection of RHRSW to LPCS for alternate injection, but even though the RHRSW pumps may survive, it is not clear that the injection line would be available after containment failure.

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
DIF	1.00E+00	1.124	DW NOT INTACT (CLASS IIID)	This is a marker event designating the failure the Drywell for class IIID scenarios. About 90% of the contribution is related to large LOCA events in which the failure of the vacuum breakers to re-close results in a vapor suppression failure. In these cases, RPV makeup is failed as a consequence of containment failure, either due to harsh reactor building environment or by injection line damage caused by containment failure. These failures could be mitigated by installing redundant vacuum breakers in each line (SAMA 20). SAMA 15 suggests the connection of RHRSW to LPCS for alternate injection, but even though the RHRSW pumps may survive, it is not clear that the injection line would be available after containment failure.
RCVCL-3D	1.00E+00	1.124	ACCIDENT CLASS IIID MARKER	Addressed in the Level 1 Importance Review.
CZF	1.00E+00	1.122	CONTAINMENT NOT INTACT BEFORE RPV BREACH (CLASS IIID)	This is a marker event designating that the containment is failed prior to RPV breach for class IIID scenarios. About 90% of the contribution is related to large LOCA events in which the failure of the vacuum breakers to re-close results in a vapor suppression failure. In these cases, RPV makeup is failed as a consequence of containment failure, either due to harsh reactor building environment or by injection line damage caused by containment failure. These failures could be mitigated by installing redundant vacuum breakers in each line (SAMA 20). SAMA 15 suggests the connection of RHRSW to LPCS for alternate injection, but even though the RHRSW pumps may survive, it is not clear that the injection line would be available after containment failure.

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LSCS "High" Importance List Review

EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
2OPAD-ALTRNT-F--	1.00E+00	1.11	ALTERNATE DEPRESS. METHODS NOT CREDITED	This event represents the failure of depressurization of the RPV through the RCIC steam lines or through the MSIVs. The RCIC steam lines are not credited because the capacity is not large enough and the MSIVs are not credited due to the time required to re-open them. However, the main contributors for these scenarios are SBOs and in these scenarios, while air could be supplied by the trailer mounted compressor, there would not be power to operate the MSIVs, among other things. The depressurization function could be restored in these cases by providing a portable DC source that could directly power panel 1(2)11Y to support Division 1 ADS and to potentially extend the operation of RCIC (SAMA 14).
2OPPH-PRESBK-F--	8.00E-01	1.11	PRESSURE TRANSIENT DOES NOT FAIL MECHANICAL SYSTEMS	This is a marker event for scenarios in which pressure transients do not fail the RCS pressure boundary (RPV not depressurized from mechanical failures after a pressure transient). The events are tied to the scenarios that include the event 2OPAD-ALTRNT-F--, which could be mitigated by providing a portable DC source that could directly power panel 1(2)11Y to support Division 1 ADS and to potentially extend the operation of RCIC (SAMA 14).
2OPPH-SORV---F--	5.50E-01	1.11	SRVs DO NOT FAIL OPEN DURING CORE MELT PROGRESSION	This is a marker event for scenarios in which the consequences of core melt do not fail the SRVs open (RPV not depressurized from a stuck open SRV after core melt). The events are tied to the scenarios that include the event 2OPAD-ALTRNT-F--, which could be mitigated by providing a portable DC source that could directly power panel 1(2)11Y to support Division 1 ADS and to potentially extend the operation of RCIC (SAMA 14).

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LSCS "High" Importance List Review

EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
2OPPH-TEMPBK-F--	7.00E-01	1.11	HIGH PRIM SYS TEMP DOES NOT CAUSE FAIL OF RCS PRESS. BOUND	This is a marker event for scenarios in which the high temperatures of core melt do not fail the RCS pressure boundary (RPV not depressurized from failed recirc pump seals, for example). The events are tied to the scenarios that include the event 2OPAD-ALTRNT-F--, which could be mitigated by providing a portable DC source that could directly power panel 1(2)11Y to support Division 1 ADS and to potentially extend the operation of RCIC (SAMA 14).
RCVSEQ-LL-ST-016	1.00E+00	1.103	ACCIDENT SEQUENCE LL-ST-016 MARKER	This event is a sequence marker representing scenarios where large LOCAs above TAF have occurred with vapor suppression failure. For this sequence, over 90% of the risk is associated with the failure of the vacuum breakers to re-close, which results in a vapor suppression failure. These failures could be mitigated by installing redundant vacuum breakers in each line (SAMA 20).
2RPCDRPS-MECHFCC	2.10E-06	1.087	RPS MECHANICAL FAILURE	Addressed in the Level 1 Importance Review.
RCVCL-4A	1.00E+00	1.081	ACCIDENT CLASS IV MARKER	Addressed in the Level 1 Importance Review.
1RBPH-RB-----F--	1.00E+00	1.075	SOURCE TERM IS NOT REDUCED BY REACTOR ENCLOSURE	The event represents the probability that the magnitude of the radioactive release will be reduced due to its passage through the RB. Considerations include gravitational settling of radionuclides, SBGT scrubbing, and scrubbing of release through a water pool. No credit is currently taken for this source term reduction mechanism. There is a potential that additional analysis could justify some type of reduction for releases through the RB, but 90% of the scenarios including this event are related large containment failures (mostly not related to hydrogen detonation). Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment overpressure (SAMA 17).
%DLOOP	7.95E-03	1.075	DUAL UNIT LOSS OF OFF-SITE POWER INITIATING EVENT	Addressed in the Level 1 Importance Review.

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LSCS "High" Importance List Review

EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
DI4-NOT	9.90E-01	1.074	DW INTACT (CLASS IV)	This is a marker event designating that the Drywell has not failed for class IV scenarios. In all of the cases including this event, combustible gas venting fails and containment failure occurs in the wetwell. The venting failure is related to the assumption that the vent capacity is not capable of keeping up with combustible gas generation. The Level 1 ATWS mitigation SAMAs, such as SAMAs 4 and 5, would provide a means of reducing the frequency of the contributors associated with this event. For ATWS scenarios, most containment failures are related to overpressurization rather than hydrogen detonation/deflagration. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment overpressure (SAMA 17).
2TDOP-RECLPS2H--	1.00E+00	1.072	OPERATOR FAILS TO RECOVER LOW PRESSURE SYSTEMS	This event represents the failure to recover low pressure systems for injection to the containment to prevent drywell failure. These are all SBO scenarios in which the low pressure systems would not have power to function. Fire water is not considered because of its low flow rate (1000 gpm required), which would be reduced from its nominal flow rate by containment pressurization. No credit is currently taken in the Level 1 model for fire protection injection due to the inability to maintain the SRVs open (and if the SRVs could be held open, the inability to perform containment vent to prevent high containment pressure would result in SRV closure due to containment pressurization). Implementation of SAMA 1 combined with the use of a portable 480V AC generator to support SRV operation (SAMA 8) would prevent core damage in these scenarios such that containment flooding would not be required.
RCVCL-IBL	1.00E+00	1.071	ACCIDENT CLASS IBL MARKER	Addressed in the Level 1 Importance Review.

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LSCS "High" Importance List Review

EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
DLOOP-IE-SW	3.84E-01	1.067	COND. PROBABILITY DLOOP DUE TO SEVERE WEATHER EVENT	Addressed in the Level 1 Importance Review.
TD6	1.00E+00	1.066	WATER INJECTION TO CONT. UNAVAIL. (CLASS II AND OP=S)	The TD6 description indicates that it is used to represent the failure to provide injection to the containment in class II events, but the model also applies it to class IV events and in quantification, it is always paired with ATWS in the "high" release categories. The TD6 failure probability is set to 1.0 because all injection systems were previously asked in the tree and were determined to be failed, which may be caused by harsh reactor building environment from containment failure or by injection line disruption on containment failure (although, energetic containment failures are not large contributors for this case). In these cases, 100% of the contribution is associated with large containment failures, which are assumed for ATWS events due to the inability of the vent to accommodate the ATWS heat loads. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure and the subsequent loss of injection systems (SAMA 17). Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).
DGRECOV-7HR	1.00E+00	1.062	DIESEL GENERATOR RECOVERY WITHIN 7 HOURS	Addressed in the Level 1 Importance Review.

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LSCS "High" Importance List Review

EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
2SYPPBOCINRB-R--	2.34E-01	1.062	BOC INITIATING EVENT PIPE BREAK OCCURS BELOW TAF (OUTSIDE STEAM TUNNEL)	These events are related to breaks outside of containment below TAF. In these cases, an unlimited injection supply would be required to maintain core cooling. This could potentially be provided by connecting RHRSW to the LPCS injection line. Water could be sprayed onto the core to maintain core cooling and in the event that reactor building flooding causes support system damage, the flood water could potentially submerge the break point and provide some scrubbing of the release (SAMA 15).
RCVSEQ-BOC-003	1.00E+00	1.062	ACCIDENT SEQUENCE BOC-003 MARKER	This sequence marker is completely tied to event 2SYPPBOCINRB-R--.
%TT	7.98E-01	1.061	TURBINE TRIP WITH BYPASS INITIATING EVENT	Addressed in the Level 1 Importance Review.
WW4	9.00E-02	1.061	WW FAILURE BELOW WATER LINE (CLASS IV)	This event represents the probability of wetwell failure below the water line for ATWS scenarios. In these cases, 100% of the contribution is associated with large containment failures, which are assumed for ATWS events due to the inability of the vent to accommodate the ATWS heat loads. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure (SAMA 17).
%ISLOCA-LPCS	7.50E-09	1.059	LPCS INJECTION LINE ISLOCA	This event is an ISLOCA initiating event. All of the contribution is associated with event 2RHMV-BREAK--F--, which is addressed in the Level 1 importance review.
%ISLOCA-RHRA	7.50E-09	1.059	RHR A INJECTION LINE ISLOCA	This event is an ISLOCA initiating event. All of the contribution is associated with event 2RHMV-BREAK--F--, which is addressed in the Level 1 importance review.
%ISLOCA-RHRA-S	7.50E-09	1.059	RHR A SDC RETURN LINE ISLOCA	This event is an ISLOCA initiating event. All of the contribution is associated with event 2RHMV-BREAK--F--, which is addressed in the Level 1 importance review.
%ISLOCA-RHRB	7.50E-09	1.059	RHR B INJECTION LINE ISLOCA	This event is an ISLOCA initiating event. All of the contribution is associated with event 2RHMV-BREAK--F--, which is addressed in the Level 1 importance review.
%ISLOCA-RHRB-S	7.50E-09	1.059	RHR B SDC RETURN LINE ISLOCA	This event is an ISLOCA initiating event. All of the contribution is associated with event 2RHMV-BREAK--F--,

Table F.5-2a
LSCS "High" Importance List Review

EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
				which is addressed in the Level 1 importance review.
%ISLOCA-RHRC	7.50E-09	1.059	RHR C INJECTION LINE ISLOCA	This event is an ISLOCA initiating event. All of the contribution is associated with event 2RHMV-BREAK--F--, which is addressed in the Level 1 importance review.
OSPR7HR-SW	2.80E-01	1.059	FAILURE TO RECOVER OSP WITHIN 7 HOURS (SEVERE WEATHER LOOP EVENT)	Addressed in the Level 1 Importance Review.
2SY--PWR5PERCF--	1.00E+00	1.056	POWER LEVEL GREATER THAN 3%	Addressed in the Level 1 Importance Review.
1RXPH-EQPRX2-F--	1.00E+00	1.056	INDUCED FAILURE OF EQUIPMENT IN RX. BLDG. (LARGE WW FAILURE)	This event represents the probability that required equipment located in the reactor building fails after a large wetwell failure. These are about 90% ATWS cases in which the containment vent is not capable of preventing overpressurization failure. In large containment failure scenarios, injection line piping that passes through the containment is also assumed to be damaged in energetic containment failures. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure and the subsequent loss of injection systems (SAMA 17). In many of these post core damage ATWS scenarios, RPV depressurization is available and energetic containment failure has not occurred. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).

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LSCS "High" Importance List Review

EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
2RX-IBL-OPS-WTHR	7.03E-01	1.054	FAILURE TO RECOVER AC POWER FOR IBE DURING RX TIME FRAME-WTHR	This event represents the probability of failure to recover AC power in the time frame required to provide RPV makeup to prevent RPV melt-through (with RPV depressurization successful). In these SBO cases, core damage has occurred because of the inability to provide RPV makeup in long term SBOs. No credit is currently taken in the Level 1 model for fire protection injection in these cases due to the inability to maintain the SRVs open (and if the SRVs could be held open, the inability to perform containment vent to prevent high containment pressure would result in SRV closure due to containment pressurization). Implementation of SAMA 1 combined with the use of a portable 480V AC generator to support SRV operation (SAMA 8) would prevent core damage in these scenarios.
2MSOP-AT-LVL-H--	1.00E+00	1.053	HEP: RPV LEVEL LOWERED BELOW LEVEL 1 SETPOINT DURING ATWS	Addressed in the Level 1 Importance Review.
2TD-IBL-OPF-WTHR	9.33E-01	1.051	FAILURE TO RECOVER AC POWER FOR IBL DURING TD TIME FRAME (OP=S) WTHR	This event represents the probability of failure to recover AC power in the time frame required to provide RPV makeup to prevent drywell failure (with RPV depressurization failure). In these SBO cases, core damage has occurred because of the inability to provide RPV makeup in long term SBOs. No credit is currently taken in the Level 1 model for fire protection injection in these cases due to the inability to maintain the SRVs open (and if the SRVs could be held open, the inability to perform containment vent to prevent high containment pressure would result in SRV closure due to containment pressurization). Implementation of SAMA 1 combined with the use of a portable 480V AC generator to support SRV operation (SAMA 8) would prevent core damage in these scenarios.
2MSRXMSIVINLKH--	1.00E+00	1.046	HEP(REC): OPERATOR FAILS TO BYPASS LOW LEVEL MSIV INTERLOCK	Addressed in the Level 1 Importance Review.

Table F.5-2a
LSCS "High" Importance List Review

EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
%A-ST	2.29E-05	1.041	LARGE LOCA ABOVE TAF	This is an initiating event for large LOCAs above TAF. Over 90% are related to vapor suppression failures resulting from the failure of a vacuum breaker to reclose. These events could be mitigated by installing redundant vacuum breakers in each line (SAMA 20).
2OPOP-RE-ACPRH--	1.00E+00	1.04	OPERATOR FAILS TO RESTORE AC POWER DURING BOIL-OFF	This event represents the probability of failure to recover AC power in the time frame when the RCS inventory is boiling off. In these SBO cases, core damage has occurred because of the inability to provide RPV makeup in long term SBOs. No credit is currently taken in the Level 1 model for fire protection injection in these cases due to the inability to maintain the SRVs open (and if the SRVs could be held open, the inability to perform containment vent to prevent high containment pressure would result in SRV closure due to containment pressurization). Implementation of SAMA 1 combined with the use of a portable 480V AC generator to support SRV operation (SAMA 8) would prevent core damage in these scenarios.
RCVSEQ-DLOP-030	1.00E+00	1.038	ACCIDENT SEQUENCE DLOP-030 MARKER	Addressed in the Level 1 Importance Review.
2SLRX-LVLCTRLH--	1.00E+00	1.034	HEP(REC): OPERATOR FAILS TO LOWER LEVEL EARLY (ATWS)	Addressed in the Level 1 Importance Review.

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LSCS "High" Importance List Review

EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
1RXPH-FIRESYSF--	1.00E+00	1.034	FIRE SYSTEM UNAVAILABLE	This event represents the probability that the fire protection system would not be available to provide makeup to prevent RPV meltthrough. The disqualifying factor for fire protection is the requirement to provide 1000 gpm. About 80% of these scenarios are ATWS scenarios and even if a hard piped fire protection connection were installed, it would not likely be capable of preventing core damage. In many of these post core damage ATWS scenarios, however, RPV depressurization is available. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).

Table F.5-2a
LSCS "High" Importance List Review

EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
2RXOP-TERMINJH--	1.00E-01	1.032	OPERATOR INTERVENES AND TERMINATES INJECTION	This is an "error of commission" event representing the probability that the operators will erroneously terminate RPV makeup when RPV makeup is still required to prevent RPV melt-through. Since the time of the Three Mile Island accident, procedures and training have improved significantly, but injection termination has been included in the model because it is a high profile evolution. No accepted HRA methodology has been established to quantify the probability of errors of commission and there are no clear, quantifiable benefits that could be calculated from further improving procedures and training. Instead, steps to mitigate other portions of the accident sequence are suggested. ATWS events contribute to over 60% of the risk for these scenarios and could be mitigated by same SAMAs identified on the Level 1 list (e.g., 4, 5, and 21) and the containment overpressure failures could be prevented by the installation of a hard pipe containment vent capable of accommodating the ATWS heat loads (SAMA 17). The long term SBOs (18% of contribution) could be addressed by implementation of SAMA 1 combined with the use of a portable 480V AC generator to support SRV operation (SAMA 8) and would prevent core damage in these scenarios.
%BOC-MS	1.62E-08	1.032	BREAK OUTSIDE CONTAINMENT IN MAIN STEAM LINE	These events are related to breaks outside of containment below TAF. In these cases, an unlimited injection supply would be required to maintain core cooling. This could potentially be provided by connecting RHRSW to the LPCS injection line. Water could be sprayed onto the core to maintain core cooling and in the event that reactor building flooding causes support system damage, the flood water could potentially submerge the break point and provide some scrubbing of the release (SAMA 15).
RCVCL-1A	1.00E+00	1.032	ACCIDENT CLASS IA MARKER	Addressed in the Level 1 Importance Review.

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EVENT NAME	PROBABILITY	RRW	DESCRIPTION	POTENTIAL SAMAS
RCVSEQ-GTR-058	1.00E+00	1.031	ACCIDENT SEQUENCE GTR-058 MARKER	Addressed in the Level 1 Importance Review.
2CZPH-DEIN-O2F--	1.00E-02	1.03	CONTAINMENT DEINERTED OR O2 INTRODUCED	This basic event represents the probability that the containment is de-inerted or that oxygen has been introduced. The event is relevant to early containment failure scenarios caused by hydrogen detonation. Hydrogen detonation could be prevented by the installation of hydrogen ignitors (SAMA 22).
2CZPH-H2-DEFGF--	1.00E+00	1.03	HYDROGEN DEFLAGRATION OCCURS GLOBALLY	This basic event represents the probability that hydrogen detonation occurs when the containment becomes de-inerted. The event is relevant to early containment failure scenarios caused by the hydrogen detonation event. Hydrogen detonation could be prevented by the installation of hydrogen ignitors (SAMA 22).
2CZPH-STMINRTF--	5.00E-01	1.03	CONTAINMENT NOT STEAM INERTED	This basic event represents the probability that the containment is not steam inerted in scenarios where normal nitrogen inertion has failed. The event is relevant to early containment failure scenarios caused by hydrogen detonation. Hydrogen detonation could be prevented by the installation of hydrogen ignitors (SAMA 22).

Table F.5-2b
LSCS "ME" Importance List Review

Event Name	Probability	RRW	Description	Potential SAMAs
1RBPH-RB-----F--	1.00E+00	24.061	SOURCE TERM IS NOT REDUCED BY REACTOR ENCLOSURE	The event represents the probability that the magnitude of the radioactive release will be reduced due to its passage through the RB. Considerations include gravitational settling of radionuclides, SBGT scrubbing, and scrubbing of release through a water pool. No credit is currently taken for this source term reduction mechanism. There is a potential that additional analysis could justify some type of reduction for releases through the RB, but over 85% of the scenarios including this event are related large containment failures in ATWS events (mostly not related to hydrogen detonation). Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment overpressure (SAMA 17).
2GVPHCMBSTGASF--	1.00E+00	24.061	COMBUSTIBLE GAS VENTING FAILS	Over 85% of the contributors including this event are related to ATWS scenarios. In ATWS cases, the containment vent capacity is not capable of keeping up with combustible gas generation and venting is assumed to fail. These containment failures are related to overpressurization rather than hydrogen detonation/deflagration. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment overpressure and by providing a means of venting combustible gases (SAMA 17).
2NCPHNCF-----F--	1.00E+00	6.198	LARGE CONTAINMENT FAILURE CLASS IIV, IIID, OR IV	This is a marker event for large containment failure scenarios. The events are all related to ATWS events in which the containment fails because of the inability of the vent to accommodate ATWS loads. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure (SAMA 17).
RCVCL-4A	1.00E+00	5.854	ACCIDENT CLASS IV MARKER	Addressed in the Level 1 Importance Review.
2RPCDRPS-MECHFCC	2.10E-06	5.761	RPS MECHANICAL FAILURE	Addressed in the Level 1 Importance Review.

Table F.5-2b
LSCS "ME" Importance List Review

Event Name	Probability	RRW	Description	Potential SAMAs
DI4-NOT	9.90E-01	5.392	DW INTACT (CLASS IV)	This event represents the probability that containment failure does not occur in the drywell. The events are all related to ATWS events in which the containment fails because of the inability of the vent to accommodate ATWS loads. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure (SAMA 17).
TD6	1.00E+00	4.63	WATER INJECTION TO CONT. UNAVAIL. (CLASS II AND OP=S)	The TD6 description indicates that it is used to represent the failure to provide injection to the containment in class II events, but the model also applies it to class IV events and in quantification, over 85% of the contribution is linked with ATWS in the "medium-early" release category. The TD6 failure probability is set to 1.0 because all injection systems were previously asked in the tree and were determined to be failed, which may be caused by harsh reactor building environment from containment failure or by injection line disruption on containment failure (although, energetic containment failures are not large contributors for this case). In these ATWS cases, all of the contribution is associated with large containment failures, which are assumed for ATWS events due to the inability of the vent to accommodate the ATWS heat loads. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure and the subsequent loss of injection systems (SAMA 17). Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).

Table F.5-2b
LSCS "ME" Importance List Review

Event Name	Probability	RRW	Description	Potential SAMAs
WW4-NOT	9.10E-01	3.123	WW FAILURE ABOVE WATER LINE (CLASS IV)	This event represents the probability of wetwell failure below the water line for ATWS scenarios. In these cases, 100% of the contribution is associated with large containment failures, which are assumed for ATWS events due to the inability of the vent to accommodate the ATWS heat loads. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure (SAMA 17).
%TT	7.98E-01	2.374	TURBINE TRIP WITH BYPASS INITIATING EVENT	Addressed in the Level 1 Importance Review.
1RXPH-EQPRX2-F--	1.00E+00	2.337	INDUCED FAILURE OF EQUIPMENT IN RX. BLDG. (LARGE WW FAILURE)	This event represents the probability that required equipment located in the reactor building fails after a large wetwell failure. These are over 85% ATWS cases in which the containment vent is not capable of preventing overpressurization failure. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure and the subsequent loss of injection systems (SAMA 17). In many of these post core damage ATWS scenarios, RPV depressurization is available. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).
2SY--PWR5PERCF--	1.00E+00	2.123	POWER LEVEL GREATER THAN 3%	Addressed in the Level 1 Importance Review.
2MSOP-AT-LVL-H--	1.00E+00	1.999	HEP: RPV LEVEL LOWERED BELOW LEVEL 1 SETPOINT DURING ATWS	Addressed in the Level 1 Importance Review.
2MSRXMSIVINLKH--	1.00E+00	1.868	HEP(REC): OPERATOR FAILS TO BYPASS LOW LEVEL MSIV INTERLOCK	Addressed in the Level 1 Importance Review.

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Event Name	Probability	RRW	Description	Potential SAMAs
1RXPH-FIRESYSF--	1.00E+00	1.579	FIRE SYSTEM UNAVAILABLE	This event represents the probability that the fire protection system would not be available to provide makeup to prevent RPV meltthrough. The disqualifying factor for fire protection is the requirement to provide 1000 gpm. Over 70% of these scenarios are ATWS scenarios and even if a hard piped fire protection connection were installed, it would not likely be capable of preventing core damage. In many of these post core damage ATWS scenarios, however, RPV depressurization is available. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).
2SLRX-LVLCTRLH--	1.00E+00	1.574	HEP(REC): OPERATOR FAILS TO LOWER LEVEL EARLY (ATWS)	Addressed in the Level 1 Importance Review.
RCVSEQ-ATW1-037	1.00E+00	1.457	ACCIDENT SEQUENCE ATW1-037 MARKER	Addressed in the Level 1 Importance Review.
2RXOP-ALTINJ-H--	1.00E-01	1.281	OPERATOR FAILS TO ALIGN INJECTION TO THE REACTOR VESSEL PRIOR TO VESSEL MELTING	This event represents the probability that alternate injection would not be aligned in time to provide makeup to prevent RPV meltthrough. The condensate system is technically considered, but the HRA conservatively uses the complex alignment of fire water injection as the execution basis for the action. In many of these post core damage ATWS scenarios, RPV depressurization is available. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).

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Event Name	Probability	RRW	Description	Potential SAMAs
2SLRX-IN-LATEH--	1.00E+00	1.277	HEP(REC): OPERATOR FAILS TO INITIATE SBLC LATE (COND PROB)	Addressed in the Level 1 Importance Review.
2RXOP-TERMINJH--	1.00E-01	1.27	OPERATOR INTERVENES AND TERMINATES INJECTION	This is an "error of commission" event representing the probability that the operators will erroneously terminate RPV makeup when RPV makeup is still required to prevent RPV melt-through. Since the time of the Three Mile Island accident, procedures and training have improved significantly, but injection termination has been included in the model because it is a high profile evolution. No accepted HRA methodology has been established to quantify the probability of errors of commission and there are no clear, quantifiable benefits that could be calculated from further improving procedures and training. Instead, steps to mitigate other portions of the accident sequence are suggested. ATWS events contribute to over 95% of the risk for these scenarios and could be mitigated by same SAMAs identified on the Level 1 list (e.g., 4, 5, and 21) and the containment overpressure failures could be prevented by the installation of a hard pipe containment vent capable of accommodating the ATWS heat loads (SAMA 17).
2FWRXMOV10AB-H--	1.00E+00	1.219	HEP(REC): OPERATOR FAILS TO CLOSE THE TDRFP DISCHARGE MOVS 2FW010A & B	Addressed in the Level 1 Importance Review.
2SLRX-LATELVLH--	1.00E+00	1.187	HEP(REC): OPERATOR FAILS TO CONTROL LEVEL LATE IN ATWS (COND PROB)	Addressed in the Level 1 Importance Review.
RCVSEQ-ATW1-041	1.00E+00	1.183	ACCIDENT SEQUENCE ATW1-041 MARKER	Addressed in the Level 1 Importance Review.

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Event Name	Probability	RRW	Description	Potential SAMAs
RX12-NOT	6.70E-01	1.178	CORE MELT ARRESTED IN-VESSEL (CLASS IV, OP=S)	This event represents the probability that injection was aligned in time to provide makeup to prevent RPV meltthrough. These are all ATWS cases in which the containment vent is not capable of preventing overpressurization failure. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure and the subsequent loss of injection systems (SAMA 17).
WW4	9.00E-02	1.156	WW FAILURE BELOW WATER LINE (CLASS IV)	This event represents the probability of wetwell failure below the water line for ATWS scenarios. In these cases, 100% of the contribution is associated with large containment failures, which are assumed for ATWS events due to the inability of the vent to accommodate the ATWS heat loads. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure (SAMA 17).
RCVCL-2	1.00E+00	1.148	ACCIDENT CLASS II MARKER	Addressed in the Level 1 Importance Review.
GEN-EMERG	5.00E-02	1.148	GENERAL EMERGENCY NOT DECLARED	The event represents the probability that a general emergency will be declared in time to provide adequate evacuation time for the public. In these cases, it has failed and the result in an "early" release. This probability is not driven by any plant specific characteristics and no insights are available to that would allow specific changes to plant procedures or training to improve the reliability of the action. About 60% of these cases are related to the failure to initiate SPC and to vent containment, which could be mitigated by automating SPC initiation (SAMA 2) or by including a passive vent in the hard pipe vent design (SAMA 3). Also, about 50% of the contribution is related to the failure to close the turbine driven pump discharge valves after the pumps are shut down. The frequency of these contributors could be reduced by changing the logic to auto close the TDRFP discharge valves when the pumps are tripped or are not running (SAMA 10).

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Event Name	Probability	RRW	Description	Potential SAMAs
2NCPHNC3-----F--	1.00E+00	1.136	LARGE CONTAINMENT FAILURE CLASS IIA OR IIL	This event represents the probability of large containment failure for class IIA or IIL sequences. Over 60% of the contributors include operator failures to initiate SPC and containment venting. A potential means of reducing risk for these scenarios would be to automate SPC initiation on high suppression pool temperature in non-LOCA scenarios (SAMA 2). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3). Reactor vessel meltthrough also occurs in over 75% of these cases due to harsh reactor building conditions. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).
2RX-SL-MS2--3H--	4.70E-02	1.134	2SLOP-LVLCTRLH-- 2MSOPMSIVINLKH-- 2SLOP-LATELVLH--	Addressed in the Level 1 Importance Review.
2RX-SL-MS1--3H--	4.50E-02	1.127	2SLOP-LVLCTRLH-- 2MSOPMSIVINLKH-- 2SLOP-IN-LATEH--	Addressed in the Level 1 Importance Review.
%TC	1.33E-01	1.116	LOSS OF CONDENSER VACUUM INITIATING EVENT	Addressed in the Level 1 Importance Review.

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Event Name	Probability	RRW	Description	Potential SAMAs
RCVSEQ-ATW1-046	1.00E+00	1.103	ACCIDENT SEQUENCE ATW1-046 MARKER	This event is a sequence marker representing ATWS scenarios in which SBLC injection/level control fails, feedwater fails, and the condenser fails. Makeup to the RPV and containment have also failed to prevent vessel melt-through and drywell failure. These are all ATWS cases in which the containment vent is not capable of preventing overpressurization failure. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure and the subsequent loss of injection systems (SAMA 17). In many of these post core damage ATWS scenarios, RPV depressurization is available. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).
RCVSEQ-ATW1-032	1.00E+00	1.102	ACCIDENT SEQUENCE ATW1-032 MARKER	Addressed in the Level 1 Importance Review.
2RX--LVL-SL-2H--	6.50E-02	1.095	2SLOP-LVLCTRLH-- 2SLOP-IN-LATEH--	Addressed in the Level 1 Importance Review.
2SY--RB-CT---F--	1.00E+00	1.09	COND. PROB. OF ECCS FAILURE DUE TO ENV. IN REACTOR BUILDING	Addressed in the Level 1 Importance Review.
2ADRXOVERFL-EH--	1.00E+00	1.089	HEP(REC): OPERATOR FAILS TO PREVENT RPV OVERFILL (DEPRESS/FW/EARLY LEVEL CONTROL	Addressed in the Level 1 Importance Review.

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Event Name	Probability	RRW	Description	Potential SAMAs
2ADRXOVERFLEEH--	1.00E+00	1.089	HEP(REC): OPERATOR FAILS TO PREVENT RPV OVERFILL (DEPRESS/NO FW AVAIL)	This event is an operator action marker that is used in cutsets where the associated HFE is combined with other HFEs. The action itself if for preventing uncontrolled injection in an ATWS and not overfilling when level is restored after successful SBLC injection. In this release category, about 85% of the contributors also include the failure of the operators to close the turbine driven feedwater pump discharge valves after the pumps are shut down. Automating level control and the "terminate and prevent" action is a potential means of addressing the risk associated with this action (SAMA 21). Alternatively, the frequency of these contributors could be reduced by changing the logic to auto close the TDRFP discharge valves when the pumps are tripped or are not running (SAMA 10).
2RX--MS-AD-32H--	3.90E-02	1.088	2MSOPMSIVINLKH-- 2ADOPOVERFL-EH--	Addressed in the Level 1 Importance Review.
2RHRXSPCINIT-H--	1.00E+00	1.087	HEP(REC): OPERATOR FAILS TO INITIATE SUPPRESSION POOL COOLING (NON-ATWS)	Addressed in the Level 1 Importance Review.
2RHRXSPCLATE-H--	1.00E+00	1.087	HEP(REC): OPERATOR FAILS TO INITIATE SPC LATE GIVEN EARLY FAILURE (COND PROB)	Addressed in the Level 1 Importance Review.
2HDOP-HD-VENTH--	9.00E-01	1.086	VENTING CREATES ADVERSE ENV. CONDITIONS FOR ALIGNMENT OF HD	Addressed in the Level 1 Importance Review.
2CVRXVENT----H--	1.00E+00	1.079	HEP(REC): OPERATOR FAILS TO INITIATE PRIMARY CONTAINMENT VENTING	Addressed in the Level 1 Importance Review.
2SLRX-IN-ERLYH--	1.00E+00	1.076	HEP(REC): OPERATOR FAILS TO INITIATE SBLC EARLY	Addressed in the Level 1 Importance Review.

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Event Name	Probability	RRW	Description	Potential SAMAs
2RX--AD-FW--2H--	7.10E-03	1.074	2ADOPOVERFLEEH-- 2FWOPMOV10AB-H--	This event is a JHEP representing the failure to control level after SBLC injection and to close the turbine driven pump discharge valves after the pumps are shut down. Automating level control and the "terminate and prevent" action is a potential means of addressing the risk associated with this action (SAMA 21). Alternatively, the frequency of these contributors could be reduced by changing the logic to auto close the TDRFP discharge valves when the pumps are tripped or are not running (SAMA 10).
2MSOPMSIVINLKH--	7.00E-01	1.069	HEP: OPERATOR FAILS TO BYPASS LOW LEVEL MSIV INTERLOCK	Addressed in the Level 1 Importance Review.
DI1	5.00E-01	1.067	DW NOT INTACT (CLASS II OR WHEN RX = S)	This event represents the probability that the drywell has failed in Class II scenarios. Over 60% of the contributors include operator failures to initiate SPC and containment venting. A potential means of reducing risk for these scenarios would be to automate SPC initiation on high suppression pool temperature in non-LOCA scenarios (SAMA 2). If a rupture disk were installed in parallel with the remotely operated hard pipe containment vent valve, it would provide a passive means of heat removal that would not compromise the equipment in the reactor building (SAMA 3). Reactor vessel meltthrough also occurs in over 75% of these cases due to harsh reactor building conditions. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).
RCVSEQ-ATW1-036	1.00E+00	1.064	ACCIDENT SEQUENCE ATW1-036 MARKER	Addressed in the Level 1 Importance Review.

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Event Name	Probability	RRW	Description	Potential SAMAs
2FWOPMOV10AB-H--	4.20E-02	1.063	HEP: OPERATOR FAILS TO CLOSE THE TDRFP DISCHARGE MOVS 2FW010A & B	Addressed in the Level 1 Importance Review for the equivalent marker event that is used when it is included in JHEPs (2FWRXMOV10AB-H--).
DI1-NOT	5.00E-01	1.061	DW INTACT (CLASS II OR WHEN RX = S)	This event represents the probability that the drywell does not fail given that the core melt was arrested in-vessel. In over 90% of the cases, the containment failure occurs in the wetwell air space due to overpressurization. Around 65% of the contributors are related to the failure to initiate SPC and to vent containment, which could be mitigated by automating SPC initiation (SAMA 2) or by including a passive vent in the hard pipe vent design (SAMA 3). In about 35% of the cases, SAMA 1 will provide a means of venting even when support systems have failed.
RCVSEQ-GTR-023	1.00E+00	1.056	ACCIDENT SEQUENCE GTR-023 MARKER	Addressed in the Level 1 Importance Review.
WW1-NOT	8.60E-01	1.055	WW FAILURE ABOVE WATER LINE (CLASS II OR RX = S)	This event represents the probability that the wetwell failure occurs above the waterline given that the core melt was arrested in-vessel. About 65% of these cases are related to the failure to initiate SPC and to vent containment, which could be mitigated by automating SPC initiation (SAMA 2) or by including a passive vent in the hard pipe vent design (SAMA 3). For the cases where vent failure occurs due to support system failures, the reliable hard pipe vent will provide a means of venting (SAMA 1).

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Event Name	Probability	RRW	Description	Potential SAMAs
2ADRXINHIBIT-H--	1.00E+00	1.053	HEP(REC): OPERATOR FAILS TO INHIBIT ADS IN ATWS (NO HP INJECTION)	This event is an operator action marker that is used in cutsets where the associated HFE (inhibit ADS in ATWS) is combined with other HFEs. The significance of this action would be reduced if the ATWS response actions were automated (SAMA 21). Additionally, these are all ATWS cases in which the containment vent is not capable of preventing overpressurization failure. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure and the subsequent loss of injection systems (SAMA 17). In many of these post core damage ATWS scenarios, RPV depressurization is available. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).
2SLOP-LVLCTRLH--	2.70E-01	1.049	HEP: OPERATOR FAILS TO LOWER LEVEL EARLY (ATWS)	Addressed in the Level 1 Importance Review.
%TIA	9.92E-03	1.048	LOSS OF INSTRUMENT AIR INITIATING EVENT	Addressed in the Level 1 Importance Review.

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Event Name	Probability	RRW	Description	Potential SAMAs
2SLOP-LATELVLH--	1.20E-01	1.047	HEP: OPERATOR FAILS TO CONTROL LEVEL LATE IN ATWS (COND PROB)	The limited time available for response is dominant PSF controlling the relatively large level control HEP. The installation of an automatic ATWS level control system that reduces level to just above -129 inches, inhibits ADS, and performs the "terminate and prevent" step (to disallow other non-feedwater RPV injection) could improve the reliability of the level reduction action and provide additional time for the operators to perform other required actions (SAMA 21). Failure to arrest core melt in-vessel is also a Level 2 contributor. In many of these post core damage ATWS scenarios, RPV depressurization is available. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).
%TF	5.65E-02	1.047	LOSS OF FEEDWATER INITIATING EVENT	Addressed in the Level 1 Importance Review.
2ADRXOVERFL-LH--	1.00E+00	1.046	HEP(REC): OPERATOR FAILS TO PREVENT RPV OVERFILL (DEPRESS/FW/LATE LEVEL CONTROL)	Addressed in the Level 1 Importance Review.
%TM	5.01E-02	1.044	MSIV CLOSURE INITIATING EVENT	Addressed in the Level 1 Importance Review.
%DLOOP	7.95E-03	1.041	DUAL UNIT LOSS OF OFF-SITE POWER INITIATING EVENT	Addressed in the Level 1 Importance Review.
2RHRXDHRRECLTH--	4.40E-01	1.04	FAIL TO RECOVERY DECAY HEAT REMOVAL LONG TERM	Addressed in the Level 1 Importance Review.
2RX-SL-MS3-23H--	1.50E-02	1.039	2SLOP-IN-ERLYH-- 2MSOPMSIVINLKH-- 2SLOP-LATELVLH--	Addressed in the Level 1 Importance Review.

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Event Name	Probability	RRW	Description	Potential SAMAs
2RX-AD-FWMS-3H--	3.70E-03	1.036	2ADOPINHIBIT-H-- 2FWOPMOV10AB-H-- 2MSOPMSIVINLKH--	This joint HEP represents failure to bypass the MSIV low level isolation logic, inhibit ADS, and close the turbine driven feedwater pump discharge valves after shutdown. The high failure probability associated with the action to bypass the MSIV low level isolation logic is due to the short response time available and the relatively long time required to perform the action. Installing a keylock MSIV low level isolation bypass switch would reduce the time required for this action and improve the reliability of the action. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further (SAMA 4). The frequency of these contributors could be reduced by changing the logic to auto close the TDRFP discharge valves when the pumps are tripped or are not running (SAMA 10).
2MSOPMSIVINLKHSU	3.00E-01	1.036	HEP: OP SUCCESSFULLY BYPASSES MSIV LOW LEVEL INTERLOCK	Addressed in the Level 1 Importance Review.
2SPPHSUPPBYPSF--	1.00E+00	1.034	SUPPRESSION POOL BYPASSED	The event represents cases in which the release bypasses the suppression pool. This can be due to events such as drywell failure and downcomer failure. For about 45% of the cases, the drywell failures are from ATWS related overpressurization. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure and the subsequent loss of injection systems (SAMA 17). The remaining cases are related to the failure to initiate SPC and to vent containment, which could be mitigated by automating SPC initiation (SAMA 2) or by including a passive vent in the hard pipe vent design (SAMA 3).
2CN-LEAK-WWAF--	1.17E-01	1.033	WW AIRSPACE LEAK	Addressed in the Level 1 Importance Review.

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Event Name	Probability	RRW	Description	Potential SAMAs
2FWAV2FW005--M--	1.34E-02	1.033	FW MDRFP 2FW01PC FEED REG AOV 2FW005 MUA	This event represents the maintenance unavailability of the motor driven feedwater pump regulating valve. This unavailability mostly impacts ATWS cases where it is used to control level. Subsequent level control failure and overfill lead to core damage and containment failure occurs due to overpressure. Automating level control and the "terminate and prevent" action is a potential means of addressing the risk associated with this event (SAMA 21). Providing an ATWS sized hard pipe vent would also mitigate these events by preventing containment failure (SAMA 17).
2ADRX-INHIBITH--	1.00E+00	1.032	HEP(REC): OPERATORS INHIBIT ADS FOR NON-ATWS ACCIDENT SCENARIO	Addressed in the Level 1 Importance Review.
2ADRX-TRANS--H--	1.00E+00	1.032	HEP(REC): OPERATOR FAILS TO MANUALLY DEPRESSURIZE THE RPV (TRANSIENT)	Addressed in the Level 1 Importance Review.
2CN--RUPT-WWAF--	1.11E-01	1.031	WW AIR SPACE RUPTURE	Addressed in the Level 1 Importance Review.

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Event Name	Probability	RRW	Description	Potential SAMAs
RCVSEQ-ATW1-028	1.00E+00	1.031	ACCIDENT SEQUENCE ATW1-028 MARKER	This event is a sequence marker representing ATWS scenarios in which SBLC injection/level control fails and the condenser fails. Makeup to the RPV and containment has also failed to prevent vessel melt-through and drywell failure. These are all ATWS cases in which the containment vent is not capable of preventing overpressurization failure and the equipment in the reactor building fails when the containment fails. Subsequent operator errors and limited alternate injection capabilities fail to prevent RPV meltthrough. Providing an ATWS sized hard pipe vent would mitigate these events by preventing containment failure and the subsequent loss of injection systems (SAMA 17). In many of these post core damage ATWS scenarios, RPV depressurization is available. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).

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Event Name	Probability	RRW	Description	Potential SAMAs
2GVPHCMBSTGASF--	1.00E+00	24.673	COMBUSTIBLE GAS VENTING FAILS	Over 95% of the contributors including this event are Class II scenarios. Currently, containment venting for combustible gas control is assumed to fail during Class II sequences due to system dependencies (i.e., instrument air). Even though combustible gas venting fails, the containment failure mode is overpressurization rather than hydrogen detonation/deflagration. Implementation of the reliable containment hard pipe vent will provide a viable vent pathway and mitigate many of these scenarios, particularly those in which venting is failed due to support system failure. The contribution related to the failure of the operators to vent (approximately 40%) would require automated SPC initiation to avoid overpressurization (SAMA 2) or a passive containment vent (SAMA 3).
1RBPH-RB-----F--	1.00E+00	16.735	SOURCE TERM IS NOT REDUCED BY REACTOR ENCLOSURE	The event represents the probability that the magnitude of the radioactive release will be reduced due to its passage through the RB. Considerations include gravitational settling of radionuclides, SBGT scrubbing, and scrubbing of release through a water pool. No credit is currently taken for this source term reduction mechanism. There is a potential that additional analysis could justify some type of reduction for releases through the RB, but 99% of the scenarios including this event are Class II overpressurization scenarios. Implementation of the reliable containment hard pipe vent will provide a viable vent pathway and mitigate many of these scenarios, particularly those in which venting is failed due to support system failure or failure to control pressure during venting. The contribution related to the failure of the operators to vent (approximately 40%) would require automated SPC initiation to avoid overpressurization (SAMA 2) or a passive containment vent (SAMA 3).
RCVCL-2	1.00E+00	14.268	ACCIDENT CLASS II MARKER	Addressed in the Level 1 Importance Review.

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Event Name	Probability	RRW	Description	Potential SAMAs
GEN-EMERG-S	9.50E-01	14.251	GENERAL EMERGENCY DECLARED	The event represents the probability that a general emergency will be declared in time to provide adequate evacuation time for the public. In these cases, it has failed and the result in an "early" release. This probability is not driven by any plant specific characteristics and no insights are available to that would allow specific changes to plant procedures or training to improve the reliability of the action. About 40% of these cases are related to the failure to initiate SPC and to vent containment, which could be mitigated by automating SPC initiation (SAMA 2) or by including a passive vent in the hard pipe vent design (SAMA 3). Other contributors include support systems failures for which the reliable containment hard pipe vent would be an effective means of preventing containment failure (SAMA 1).
2NCPHNC3-----F--	1.00E+00	6.973	LARGE CONTAINMENT FAILURE CLASS IIA OR IIL	These are typical Class II scenarios that lead to containment failure due to overpressurization. Currently, containment venting for combustible gas control is assumed to fail during Class II sequences due to system dependencies (i.e., instrument air). Even though combustible gas venting fails, the containment failure mode is overpressurization rather than hydrogen detonation/deflagration. Implementation of the reliable containment hard pipe vent will provide a viable vent pathway and mitigate many of these scenarios, particularly those in which venting is failed due to support system failure. The contribution related to the failure of the operators to vent (approximately 40%) would require automated SPC initiation to avoid overpressurization (SAMA 2) or a passive containment vent (SAMA 3).
TD6	1.00E+00	3.984	WATER INJECTION TO CONT. UNAVAIL. (CLASS II AND OP=S)	The TD6 description indicates that it is used to represent the failure to provide injection to the containment in class II events. The TD6 failure probability is set to 1.0 because all injection systems were previously asked in the tree and were determined to be failed, which may be caused by harsh reactor building environment from containment failure or by injection line disruption on containment failure (although,

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Event Name	Probability	RRW	Description	Potential SAMAs
				energetic containment failures are not large contributors for this case). The reliable containment hard pipe vent would provide a viable vent path for many of these cases. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).
1RXPH-EQPRX2-F--	1.00E+00	3.051	INDUCED FAILURE OF EQUIPMENT IN RX. BLDG. (LARGE WW FAILURE)	This event represents the probability that required equipment located in the reactor building fails after a large wetwell failure. These are all Class II cases in which the containment vent has failed due to operator error or support system failures. Implementation of the reliable containment hard pipe vent will provide a viable vent pathway and mitigate many of these scenarios, particularly those in which venting is failed due to support system failure. The contribution related to the failure of the operators to vent (approximately 35%) would require automated SPC initiation to avoid overpressurization (SAMA 2) or a passive containment vent (SAMA 3). Other cases would be addressed by the reliable hard pipe containment vent (SAMA 1). Injection from sources outside of the reactor building could also mitigate these scenarios. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).
2HDOP-HD-VENTH--	9.00E-01	2.772	VENTING CREATES ADVERSE ENV. CONDITIONS FOR ALIGNMENT OF HD	Addressed in the Level 1 Importance Review.

Table F.5-2c
LSCS "MI" Importance List Review

Event Name	Probability	RRW	Description	Potential SAMAs
1RXPH-FIRESYSF--	1.00E+00	2.478	FIRE SYSTEM UNAVAILABLE	This event represents the probability that the fire protection system would not be available to provide makeup to prevent RPV meltthrough. The disqualifying factor for fire protection is the requirement to provide 1000 gpm. In a majority of these Class II scenarios, however, RPV depressurization is available. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).
2SY--RB-CT---F--	1.00E+00	2.325	COND. PROB. OF ECCS FAILURE DUE TO ENV. IN REACTOR BUILDING	Addressed in the Level 1 Importance Review.
2RHRXDHRRECLTH--	4.40E-01	1.927	FAIL TO RECOVERY DECAY HEAT REMOVAL LONG TERM	Addressed in the Level 1 Importance Review.
DI1	5.00E-01	1.792	DW NOT INTACT (CLASS II OR WHEN RX = S)	This event represents the probability that the wetwell failure occurs above the waterline given that the core melt was arrested in-vessel. About 40% of these cases are related to the failure to initiate SPC and to vent containment, which could be mitigated by automating SPC initiation (SAMA 2) or by including a passive vent in the hard pipe vent design (SAMA 3). For the cases where vent failure occurs due to support system failures, the reliable hard pipe vent will provide a means of venting (SAMA 1). In a majority of these Class II scenarios, RPV depressurization is available. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).

Table F.5-2c
LSCS "MI" Importance List Review

Event Name	Probability	RRW	Description	Potential SAMAs
DI1-NOT	5.00E-01	1.729	DW INTACT (CLASS II OR WHEN RX = S)	This event represents the probability that the drywell does not fail given that the core melt was arrested in-vessel. In about 90% of the cases, the containment failure occurs in the wetwell air space due to overpressurization. About half of these cases are related to the failure to initiate SPC and to vent containment, which could be mitigated by automating SPC initiation (SAMA 2) or by including a passive vent in the hard pipe vent design (SAMA 3). The other half are related to support system failures that could be mitigated by the reliable hard pipe vent (SAMA 1), which does not require support systems to operate.
2RHRXSPCINIT-H--	1.00E+00	1.639	HEP(REC): OPERATOR FAILS TO INITIATE SUPPRESSION POOL COOLING (NON-ATWS)	Addressed in the Level 1 Importance Review.
2RHRXSPCLATE-H--	1.00E+00	1.627	HEP(REC): OPERATOR FAILS TO INITIATE SPC LATE GIVEN EARLY FAILURE (COND PROB)	Addressed in the Level 1 Importance Review.
RCVSEQ-GTR-023	1.00E+00	1.604	ACCIDENT SEQUENCE GTR-023 MARKER	Addressed in the Level 1 Importance Review.
WW1-NOT	8.60E-01	1.598	WW FAILURE ABOVE WATER LINE (CLASS II OR RX = S)	This event represents the probability that the wetwell failure occurs above the waterline given that the core melt was arrested in-vessel. About 40% of these cases are related to the failure to initiate SPC and to vent containment, which could be mitigated by automating SPC initiation (SAMA 2) or by including a passive vent in the hard pipe vent design (SAMA 3). For the cases where vent failure occurs due to support system failures, the reliable hard pipe vent will provide a means of venting (SAMA 1).
2CVRXVENT----H--	1.00E+00	1.537	HEP(REC): OPERATOR FAILS TO INITIATE PRIMARY CONTAINMENT VENTING	Addressed in the Level 1 Importance Review.
2FWRXMOV10AB-H--	1.00E+00	1.382	HEP(REC): OPERATOR FAILS TO CLOSE THE TDRFP DISCHARGE MOVS 2FW010A & B	Addressed in the Level 1 Importance Review.

Table F.5-2c
LSCS "MI" Importance List Review

Event Name	Probability	RRW	Description	Potential SAMAs
BFPOP-DFPENV1H--	5.00E-01	1.308	HEP: OP FAILS TO ALIGN DFP DUE TO ADVERSE ENV IN TB (VENT TO STEAM TUNNEL)	Addressed in the Level 1 Importance Review.
2CN--RUPT-DWBF--	8.58E-02	1.289	DW BODY RUPTURE	Addressed in the Level 1 Importance Review.
%TIA	9.92E-03	1.287	LOSS OF INSTRUMENT AIR INITIATING EVENT	Addressed in the Level 1 Importance Review.
%DLOOP	7.95E-03	1.275	DUAL UNIT LOSS OF OFF-SITE POWER INITIATING EVENT	Addressed in the Level 1 Importance Review.
2CN-LEAK-WWAF--	1.17E-01	1.271	WW AIRSPACE LEAK	Addressed in the Level 1 Importance Review.
2IARXRCOVERIAH--	1.00E-01	1.268	HEP: OP FAILS TO RESTORE IA / SA FOR VENTING (NON LOOP OR DLOOP)	Addressed in the Level 1 Importance Review.
2CN--RUPT-WWAF--	1.11E-01	1.254	WW AIR SPACE RUPTURE	Addressed in the Level 1 Importance Review.
DGRECOV-7HR	1.00E+00	1.218	DIESEL GENERATOR RECOVERY WITHIN 7 HOURS	Addressed in the Level 1 Importance Review.
DLOOP-IE-SW	3.84E-01	1.216	COND. PROBABILITY DLOOP DUE TO SEVERE WEATHER EVENT	Addressed in the Level 1 Importance Review.
RCVSEQ-DLOP-014	1.00E+00	1.19	ACCIDENT SEQUENCE DLOP-014 MARKER	Addressed in the Level 1 Importance Review.
%TC	1.33E-01	1.181	LOSS OF CONDENSER VACUUM INITIATING EVENT	Addressed in the Level 1 Importance Review.
2ADRX-INHIBITH--	1.00E+00	1.176	HEP(REC): OPERATORS INHIBIT ADS FOR NON-ATWS ACCIDENT SCENARIO	Addressed in the Level 1 Importance Review.
2ADRX-TRANS--H--	1.00E+00	1.175	HEP(REC): OPERATOR FAILS TO MANUALLY DEPRESSURIZE THE RPV (TRANSIENT)	Addressed in the Level 1 Importance Review.
OSPR20HR-SW	1.33E-01	1.172	FAILURE TO RECOVER OSP WITHIN 20 HOURS (SEVERE WEATHER LOOP EVENT)	Addressed in the Level 1 Importance Review.

Table F.5-2c
LSCS "MI" Importance List Review

Event Name	Probability	RRW	Description	Potential SAMAs
RX10-II-NOT	2.00E-01	1.169	CORE MELT ARRESTED IN-VESSEL (CLASS II, OP=S)	This event represents the probability that injection is aligned in time to prevent the core from melting through the RPV. These are all Class II scenarios in which containment overpressurization has led to a large containment failure. About 40% of these cases are related to the failure to initiate SPC and to vent containment, which could be mitigated by automating SPC initiation (SAMA 2) or by including a passive vent in the hard pipe vent design (SAMA 3). For the cases where vent failure occurs due to support system failures, the reliable hard pipe vent will provide a means of venting (SAMA 1). Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).
2SPPHSUPPBYPSF--	1.00E+00	1.168	SUPPRESSION POOL BYPASSED	The event represents cases in which the release bypasses the suppression pool. This can be due to events such as drywell failure and downcomer failure. In these cases, bypass is conservatively assumed even though the Drywell is intact in about 50% of the contributors and combustible gas venting has failed. The scenarios are all Class II evolutions in which failure of heat removal leads to containment failure. About 40% of these cases are related to the failure to initiate SPC and to vent containment, which could be mitigated by automating SPC initiation (SAMA 2) or by including a passive vent in the hard pipe vent design (SAMA 3). For the cases where vent failure occurs due to support system failures, the reliable hard pipe vent will provide a means of venting (SAMA 1).
2CN--LEAK-DWBF--	7.46E-02	1.15	DW BODY LEAK	Addressed in the Level 1 Importance Review.
RCVSEQ-GTR-028	1.00E+00	1.127	ACCIDENT SEQUENCE GTR-028 MARKER	Addressed in the Level 1 Importance Review.

Table F.5-2c
LSCS “MI” Importance List Review

Event Name	Probability	RRW	Description	Potential SAMAs
2RX-FWADRHCV6H--	5.00E-07	1.12	2FWOPMOV10AB-H-- 2ADOP-INHIBITH-- 2ADOP-TRANS--H-- 2RHOPSPCINIT-H-- 2CVOPVEN	Addressed in the Level 1 Importance Review.
2FPRXALGNFPSAH--	1.00E+00	1.098	HEP(REC): OPERATOR FAILS TO ALIGN FPS FOLLOWING CONTAINMENT VENT OR FAILURE	Addressed in the Level 1 Importance Review.
BFPRX-DFPENV-H--	1.00E+00	1.097	HEP(REC): OP FAILS TO ALIGN DFP DUE TO ADVERSE ENV IN TB (VENT TO RB OR CNTNMT F	Addressed in the Level 1 Importance Review.
2RXOP-TERMINJH--	1.00E-01	1.088	OPERATOR INTERVENES AND TERMINATES INJECTION	This is an "error of commission" event representing the probability that the operators will erroneously terminate RPV makeup when RPV makeup is still required to prevent RPV melt-through. Since the time of the Three Mile Island accident, procedures and training have improved significantly, but injection termination has been included in the model because it is a high profile evolution. No accepted HRA methodology has been established to quantify the probability of errors of commission and there are no clear, quantifiable benefits that could be calculated from further improving procedures and training. Instead, steps to mitigate other portions of the accident sequence are suggested. Class II events contribute to over 90% of the risk for these scenarios and could be mitigated by same SAMAs identified on the Level 1 list (e.g., 1, 2, and 3).
2RXOP-ALTINJ-H--	1.00E-01	1.084	OPERATOR FAILS TO ALIGN INJECTION TO THE REACTOR VESSEL PRIOR TO VESSEL MELTING	This event represents the probability that alternate injection would not be aligned in time to provide makeup to prevent RPV meltthrough. The condensate system is technically considered, but the HRA conservatively uses the complex alignment of fire water injection as the execution basis for the action. In many of these post core damage ATWS scenarios, RPV depressurization is available. Installation of a cross-connect between RHRSW and LPCS that would

Table F.5-2c
LSCS "MI" Importance List Review

Event Name	Probability	RRW	Description	Potential SAMAs
				provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).
2NCPHNCF-----F--	1.00E+00	1.079	LARGE CONTAINMENT FAILURE CLASS IIV, IIID, OR IV	This is a marker event for large containment failure scenarios. Over 70% of these cases are those in which containment venting is successful and the failure of the vent pathway leads to harsh reactor building conditions and subsequent failure of the injection systems in the area. The reliable hard pipe containment vent will prevent these failures (SAMA 1).
DI3-NOT	1.00E+00	1.079	DW INTACT (CLASS IIV)	This is a marker event for cases in which the drywell remains intact. Over 70% of these cases are those in which containment venting is successful and the failure of the vent pathway leads to harsh reactor building conditions and subsequent failure of the injection systems in the area. The reliable hard pipe containment vent will prevent these failures (SAMA 1).
WW3-NOT	1.00E+00	1.079	WW FAILURE ABOVE WATER LINE (CLASS IIV)	This is a marker event for cases in which the wetwell fails in the air space (above the waterline). Over 70% of these cases are those in which containment venting is successful and the failure of the vent pathway leads to harsh reactor building conditions and subsequent failure of the injection systems in the area. The reliable hard pipe containment vent will prevent these failures (SAMA 1).
%TM	5.01E-02	1.076	MSIV CLOSURE INITIATING EVENT	Addressed in the Level 1 Importance Review.
2RX-FWRHCVF15H--	5.00E-07	1.074	2FWOPMOV10AB-H-- 2RHOPSPCINIT-H-- 2CVOPVENT----H-- 2RHOPSPCLATE-H--	Addressed in the Level 1 Importance Review.

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LSCS "MI" Importance List Review

Event Name	Probability	RRW	Description	Potential SAMAs
			2FPOPALG	
2RX-FWRHCVF35H--	5.00E-07	1.074	2FWOPMOV10AB-H-- 2RHOPSPCINIT-H-- 2CVOPVENT----H-- 2RHOPSPCLATE-H-- BFPOP-DF	Addressed in the Level 1 Importance Review.
RCVSEQ-GTR-013	1.00E+00	1.069	ACCIDENT SEQUENCE GTR-013 MARKER	Addressed in the Level 1 Importance Review.
%TF	5.65E-02	1.066	LOSS OF FEEDWATER INITIATING EVENT	Addressed in the Level 1 Importance Review.
2OPAD-ALTRNT-F--	1.00E+00	1.065	ALTERNATE DEPRESS. METHODS NOT CREDITED	This event represents the failure of depressurization of the RPV through the RCIC steam lines or through the MSIVs. The RCIC steam lines are not credited because the capacity is not large enough and the MSIVs are not credited due to the time required to re-open them. The main contributors leading to the failure of normal depressurization methods are the operator errors of improperly inhibiting ADS and failing to manually depressurize the RCS, SBO scenarios that deplete DC power, and DC bus failures. The depressurization function could be restored in DC power failure scenarios by providing a portable DC source that could directly power panel 1(2)11Y (SAMA 14). No specific improvements have been identified that could significantly reduce the probability of improperly inhibiting ADS in non-ATWS scenarios.
2OPPH-PRESBK-F--	8.00E-01	1.065	PRESSURE TRANSIENT DOES NOT FAIL MECHANICAL SYSTEMS	This is a marker event for scenarios in which pressure transients do not fail the RCS pressure boundary (RPV not depressurized from mechanical failures after a pressure transient). The events are tied to the scenarios that include the event 2OPAD-ALTRNT-F--, which could be mitigated by providing a portable DC source that could directly power panel 1(2)11Y (SAMA 14).

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LSCS "MI" Importance List Review

Event Name	Probability	RRW	Description	Potential SAMAs
2OPPH-SORV---F--	5.50E-01	1.065	SRVs DO NOT FAIL OPEN DURING CORE MELT PROGRESSION	This is a marker event for scenarios in which the consequences of core melt do not fail the SRVs open (RPV not depressurized from a stuck open SRV after core melt). The events are tied to the scenarios that include the event 2OPAD-ALTRNT-F--, which could be mitigated by providing a portable DC source that could directly power panel 1(2)11Y (SAMA 14).
2OPPH-TEMPBK-F--	7.00E-01	1.065	HIGH PRIM SYS TEMP DOES NOT CAUSE FAIL OF RCS PRESS. BOUND	This is a marker event for scenarios in which the high temperatures of core melt do not fail the RCS pressure boundary (RPV not depressurized from failed recirc pump seals, for example). The events are tied to the scenarios that include the event 2OPAD-ALTRNT-F--, which could be mitigated by providing a portable DC source that could directly power panel 1(2)11Y (SAMA 14).
2ACRX-AC-CBS-H--	1.00E+00	1.057	HEP(REC): OPERATOR FAILS TO CLOSE BREAKER TO 4KV BUS AFTER OFFSITE AC POWER RECO	Addressed in the Level 1 Importance Review.
2DGFN-VY06C--X--	3.29E-03	1.057	UNIT 2 DIV 2 CSCS ROOM COOLER FAN 2VY06C FAILS TO RUN	Addressed in the Level 1 Importance Review.
2VYFNSEVY03CBX--	3.29E-03	1.056	VY SE CORNER ROOM (RHR B & C) COOLING FAN 2VY03C FAILS TO RUN	Addressed in the Level 1 Importance Review.
%MS	1.01E+00	1.053	MANUAL SHUTDOWN INITIATING EVENT	Addressed in the Level 1 Importance Review.
WW1	1.40E-01	1.05	WW FAILURE BELOW WATER LINE (CLASS II OR RX = S)	This event represents the probability that the wetwell failure occurs above the waterline given that the core melt was arrested in-vessel. About 50% of these cases are related to the failure to initiate SPC and to vent containment, which could be mitigated by automating SPC initiation (SAMA 2) or by including a passive vent in the hard pipe vent design (SAMA 3). For the cases where vent failure occurs due to support system failures, the reliable hard pipe vent will provide a means of venting (SAMA 1).

Table F.5-2c
LSCS "MI" Importance List Review

Event Name	Probability	RRW	Description	Potential SAMAs
%TT	7.98E-01	1.049	TURBINE TRIP WITH BYPASS INITIATING EVENT	Addressed in the Level 1 Importance Review.
RCVCL-IBL	1.00E+00	1.042	ACCIDENT CLASS IBL MARKER	Addressed in the Level 1 Importance Review.
2DGPMCSDG2A--M--	3.10E-03	1.041	DG2A COOLING WATER PUMP 2DG01P TRAIN MUA	Addressed in the Level 1 Importance Review.
2CVOPVENT----H--	6.60E-03	1.038	HEP: OPERATOR FAILS TO INITIATE PRIMARY CONTAINMENT VENTING	Addressed in the Level 1 Importance Review.
RX9	1.00E+00	1.038	FAILURE TO ARREST CORE MELT IN-VESSEL (CLASS II, OP=F)	This event represents the probability that RPV meltthrough is prevented in cases where RPV depressurization has failed (all Class II scenarios). The main contributors leading to the failure of normal depressurization methods are the operator errors of improperly inhibiting ADS and failing to manually depressurize the RCS (about 80% of the contribution). No specific improvements have been identified that could significantly reduce the probability of improperly inhibiting ADS in non-ATWS scenarios and in most cases, the probability of the JHEPs including this actions are already set to the lowest allowable value for a JHEP (further improvements in human reliability would not be credited). These scenarios could be mitigated by automating SPC initiation (SAMA 2) or by including a passive vent in the hard pipe vent design (SAMA 3).

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LSCS "MI" Importance List Review

Event Name	Probability	RRW	Description	Potential SAMAs
TD5	1.00E+00	1.038	WATER INJECTION TO CONT. UNAVAIL. (CLASS II AND OP=F, OR IIID,IV)	The TD5 description indicates that it is used to represent the failure to provide injection to the containment in class II, IIID, or IV events. The TD5 failure probability is set to 1.0 because all injection systems were previously asked in the tree and were determined to be failed, which may be caused by harsh reactor building environment from containment failure or by injection line disruption on containment failure (although, energetic containment failures are not large contributors for this case). The contributors including the TD5 event are essentially the same as those for RX9, but after vessel meltthrough, low pressure systems could be used for injection due to reduced RCS pressure. Installation of a cross-connect between RHRSW and LPCS that would provide a high flow, low pressure makeup system that is not currently available (SAMA 15). Alternatively, the Fuel Pool Emergency Makeup System could be modified to include a higher pressure/higher capacity pump and a permanent connection to the RHR "B" line could be installed with manual isolation valves (SAMA 23).
2RHPME12C002BM--	2.97E-03	1.034	RH TRAIN 2B (2E12-C002B) MUA	Addressed in the Level 1 Importance Review.
RCVSEQ-DLOP-021	1.00E+00	1.034	ACCIDENT SEQUENCE DLOP-021 MARKER	This event is an accident sequence marker for dual unit LOOP events with initial success of the HPCS system and no heat removal. Venting failure results in a harsh reactor building environment, which subsequently fails HPCS. In these cases, venting is failed by support system failures, which would be mitigated by the reliable hard pipe vent (SAMA 1) given that it does not rely on support systems for operation.
BFPOP-DFPENV-H--	1.00E-01	1.033	HEP: OP FAILS TO ALIGN DFP DUE TO ADVERSE ENV IN TB (VENT TO RB OR CNTNMT FAIL)	Addressed in the Level 1 Importance Review.
1DGFN-VY05C--X--	3.29E-03	1.033	UNIT 1 DIV 1 CSCS ROOM COOLER FAN 1VY05C FAIL TO	Addressed in the Level 1 Importance Review.

Table F.5-2c
LSCS "MI" Importance List Review

Event Name	Probability	RRW	Description	Potential SAMAs
			RUN	
OP5-NOT	7.05E-01	1.033	SUCCESSFULLY DEPRESSURIZE RPV (CLASS IBL)	This event represents the probability that the RPV is depressurized in long term SBOs. The OP5 gate includes, among other things, the probabilities that induced LOCAs do not occur. For the NOT version of the OP5 contributor, one or more of these events has likely occurred to depressurize the RPV. SBO events, in general, were addressed in the Level 1 importance review.
2FWRXTDRFPS--H--	1.00E+00	1.031	HEP(REC): OPERATOR FAILS TO MANUALLY RESET LEVEL 8 TRIP OR RESTART FW	Addressed in the Level 1 Importance Review.
2VYFNNWVY01--X--	3.29E-03	1.031	VY NW CORNER ROOM (RHR A) COOLING FAN 2VY01C FAILS TO RUN	Addressed in the Level 1 Importance Review.
2DGFN-VY05C--X--	3.29E-03	1.031	UNIT 2 DIV 1 CSCS ROOM COOLER FAN 2VY05C FAIL TO RUN	Addressed in the Level 1 Importance Review.
2CD--2CD01AMS---	3.00E-02	1.03	COND PROBY MAN SHTDWN REQD FOR MAIN CONDENSER 2CD01A MAINT	Addressed in the Level 1 Importance Review.
2CVSYVNT-ATWSF--	1.00E+00	1.03	CONTAINMENT VENT CONSERVATIVELY NOT CREDITED FOR ATWS	Addressed in the Level 1 Importance Review.
2SY--VENT1---FCC	9.99E-03	1.03	CCF OF HPCS & CRD & LPCI & LPCS GIVEN VENT TO STEAM TUNNEL	Addressed in the Level 1 Importance Review.
2RPCDRPS-MECHFCC	2.10E-06	1.03	RPS MECHANICAL FAILURE	Addressed in the Level 1 Importance Review.

Table F.5-3a
Approximated RMIEP Seismic CDF Results

Accident Sequence	Earthquake Level (g PGA) Level 1 (0.18-0.27)	Level 2 (0.27-0.36)	Level 3 (0.36-0.46)	Level 4 (0.46-0.58)	Level 5 (0.58-0.73)	Level 6 (>0.73)	Accident Sequence Total (per year)
Large-LOCA-1	1.9E-11	8.4E-12	5.0E-12	3.0E-12	1.8E-12	1.1E-12	3.8E-11
Large-LOCA-2	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Large-LOCA-3	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Medium-LOCA-1	7.2E-10	3.2E-10	1.9E-10	1.1E-10	6.9E-11	4.2E-11	1.4E-09
Medium-LOCA-2	7.9E-10	2.3E-10	9.4E-11	4.4E-11	2.1E-11	1.2E-11	1.2E-09
Medium-LOCA-3	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Medium-LOCA-4	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Small-LOCA-1	4.7E-09	1.9E-09	9.8E-10	4.7E-10	2.3E-10	8.8E-11	8.4E-09
Small-LOCA-2	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Small-LOCA-3	1.5E-08	7.0E-09	4.1E-09	2.4E-09	1.5E-09	9.3E-10	3.1E-08
Small-LOCA-4	1.8E-08	4.9E-09	2.1E-09	9.9E-10	4.8E-10	2.5E-10	2.6E-08
Small-LOCA-5	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Small-LOCA-6	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
LOSP-Trans-1	3.9E-08	1.6E-08	8.0E-09	4.0E-09	1.8E-09	7.2E-10	6.9E-08
LOSP-Trans-2	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
LOSP-Trans-3	1.3E-07	5.8E-08	3.3E-08	2.0E-08	1.2E-08	7.5E-09	2.6E-07
LOSP-Trans-4	1.4E-07	4.1E-08	1.7E-08	8.0E-09	4.0E-09	2.1E-09	2.1E-07
LOSP-Trans-5	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
LOSP-Trans-6	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
LOSP-Trans-7	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Interval Total (per year)	3.5E-07	1.3E-07	6.5E-08	3.6E-08	2.0E-08	1.2E-08	Grand Total 6.1E-07

Table F.5-3b
RMIEP Seismic CDF Results Updated with the LSCS 2013 Seismic Hazard Curve

Accident Sequence	Earthquake Level (g PGA) Level 1 (0.18-0.27)	Level 2 (0.27-0.36)	Level 3 (0.36-0.46)	Level 4 (0.46-0.58)	Level 5 (0.58-0.73)	Level 6 (>0.73)	Accident Sequence Total (per year)
Large-LOCA-1	1.4E-11	8.8E-12	7.0E-12	5.3E-12	4.0E-12	5.1E-12	4.4E-11
Large-LOCA-2	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Large-LOCA-3	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Medium-LOCA-1	5.4E-10	3.3E-10	2.6E-10	2.0E-10	1.5E-10	1.9E-10	1.7E-09
Medium-LOCA-2	6.0E-10	2.4E-10	1.3E-10	7.9E-11	4.6E-11	5.6E-11	1.1E-09
Medium-LOCA-3	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Medium-LOCA-4	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Small-LOCA-1	3.6E-09	2.0E-09	1.4E-09	8.5E-10	5.1E-10	4.1E-10	8.7E-09
Small-LOCA-2	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Small-LOCA-3	1.2E-08	7.3E-09	5.7E-09	4.4E-09	3.3E-09	4.3E-09	3.7E-08
Small-LOCA-4	1.3E-08	5.2E-09	2.9E-09	1.8E-09	1.1E-09	1.2E-09	2.5E-08
Small-LOCA-5	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Small-LOCA-6	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
LOSP-Trans-1	2.9E-08	1.6E-08	1.1E-08	7.2E-09	4.0E-09	3.3E-09	7.1E-08
LOSP-Trans-2	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
LOSP-Trans-3	1.0E-07	6.1E-08	4.7E-08	3.6E-08	2.7E-08	3.5E-08	3.0E-07
LOSP-Trans-4	1.1E-07	4.2E-08	2.3E-08	1.4E-08	8.8E-09	9.7E-09	2.1E-07
LOSP-Trans-5	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
LOSP-Trans-6	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
LOSP-Trans-7	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Interval Total (per year)	2.7E-07	1.3E-07	9.2E-08	6.4E-08	4.5E-08	5.4E-08	Grand Total 6.6E-07

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
1	Install Reliable Hard Pipe Containment Vent	This is already a commitment for LSCS, but it has not yet been installed and is not modeled in the PRA. This SAMA, which will prevent vent path failure within the reactor building and will provide a means of safely operating the containment vent when normal support systems are unavailable (non-adverse environment for use of portable pneumatic supply or manual valve operation). This SAMA is used to track this enhancement in the analysis and to facilitate the interpretation of the results.	LSCS Level 1 and 2 Importance Review	The LSCS specific cost estimate for implementation of this SAMA is $12.94 million (S&L 2014). This LSCS estimate does not include contingency costs.	Implementation is planned. Evaluated in the Phase II analysis to document the impact of implementation.
2	Automate Suppression Pool Cooling Initiation	Suppression pool cooling initiation is a reliable action, but for non-LOCA events, automating SPC initiation on high suppression pool temperature could further improve the reliability of the containment heat removal function.	LSCS Level 1 and 2 Importance Review	$400,000 (TVA, 2003)	Implementation cost is less than MACR. Retain for Phase II analysis.

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
3	Passive Vent Path	For loss of containment heat removal scenarios, the reliability of the containment venting function could be improved by installing a passive vent path. If the suppression chamber vent path were equipped with a rupture disk in parallel with the remotely operated vent path, a scrubbed release path would be available to prevent containment failure in the event that normal venting fails. The rupture disk failure pressure would have to be less than the ultimate containment strength to ensure it would rupture before the containment, but consideration could also be given to a lower pressure to ensure SRVs could remain operable to support low pressure injection in loss of containment heat removal cases. Effectiveness is contingent on the implementation of the hard pipe vent.	LSCS Level 1 and 2 Importance Review	The cost of a passive vent was estimated to cost $1,000,000 at Oyster Creek (AmerGen 2005).	Implementation cost is less than MACR. Retain for Phase II analysis.

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
4	Install a Keylock MSIV Low Level Isolation Bypass Switch	Operator errors are some of the largest contributors to ATWS scenarios, which are complicated by the short times available for response. One of the more time limited actions in these scenarios is the action to bypass the MSIV low level isolation signal, which is currently an action that requires the installation of jumpers. Providing a switch in the MCR that would bypass the isolation logic would simplify the bypass action and provide more time margin for the power/level control actions for these scenarios. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further.	LSCS Level 1 and 2 Importance Review	The LSCS specific cost estimate for implementation of this SAMA is $635,242 (S&L 2014).	Implementation cost is less than MACR. Retain for Phase II analysis.
5	Automate SBLC Initiation	ATWS events rely on timely initiation of the SBLC system for mitigation. A potential means of improving the reliability of this function would be to automate system initiation, as is that case at Limerick Generation Station.	LSCS Level 1 and 2 Importance Review	The cost of automating SBLC operation at Browns Ferry was estimated to be $400,000 (TVA, 2003)	Implementation cost is less than MACR. Retain for Phase II analysis.

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
6	Create ECCS Suction Strainer Backflush Capability with RHRSW	For some LOCA contributors, common cause plugging of the ECCS suction strainers fails makeup/heat removal. Connecting the RHRSW system to the RHR pump suction line upstream of the F004A/B valves could provide a means of backflushing the system in conjunction with steps to close the F004A/B valves during the backflush.	LSCS Level 1 and 2 Importance Review	$2,900,000 (NMC 2005) Note: Palisades developed this cost for installing a fire water to SW x-tie, operable from MCR. Because this SAMA must mitigate LOCAs, rapid alignment is required and control from the MCR is considered to be required.	Implementation cost is less than MACR. Retain for Phase II analysis.
7	Water Hammer Prevention	Alter the LOCA signal logic to require both high drywell pressure AND low water level for initiation. This will prevent LOCA signals in transient scenarios where high DW pressure alone can cause consequential LOOP events and drain the discharge line of an RHR train running in SPC mode (PRA specific scenario). This could also have the added benefit of simplifying the operators' response to loss of offsite power events where the LOOP signal has caused the EDGs to start and load and an ECCS signal is subsequently received due to loss of containment cooling (high drywell pressure). In this LOOP-delayed LOCA scenario, the operators are required to take many actions to handle the automatic actuations that occur due to the LOCA signal. This scenario is not specifically modeled in the PRA.	LSCS Level 1 and 2 Importance Review	The LSCS specific cost estimate for implementation of this SAMA is $962,403 (S&L 2014).	Implementation cost is less than MACR. Retain for Phase II analysis.

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
8	Obtain a 480V AC Portable Generator to Supply the 125V DC Battery Chargers and Proceduralize its Use	For long term SBO scenarios, the hardened containment vent that LSCS is committed to install will provide a means of containment heat removal, but the battery life is currently assumed to be limited to about 7 hours in the PRA model. After battery depletion, the SRVs will close and the RPV will re-pressurize and prevent injection with a low pressure system, such as the fire protection system. Use of a portable generator to provide power to the 125V DC battery chargers would provide a means of maintaining the SRVs open, energize critical instrumentation, and ensure RPV pressure remains low enough for use of low pressure alternate makeup systems.	LSCS Level 1 and 2 Importance Review	The cost of a portable 480V AC generation was estimated by Ginna to be $400,000 (RG&E 2002)	Implementation cost is less than MACR. Retain for Phase II analysis.
9	Develop Flood Zone Specific Procedures	The reliability of the internal flood mitigation actions could be improved by developing location and system specific flood response procedures. For example, for fire protection floods in the reactor building, developing procedures that direct the isolation of the FP070 and FP080 valves could significantly reduce the time required to terminate reactor building floods from the fire protection system. Increasing the time margin for the operators to respond to the floods would improve the likelihood of preventing damage to critical ECCS equipment.	LSCS Level 1 and 2 Importance Review	The LSCS specific cost estimate for implementation of this SAMA is $115,000 (S&L 2014).	Implementation cost is less than MACR. Retain for Phase II analysis.

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
10	Change the Logic to Close the Turbine Driven Feedwater Pump Discharge Valves When the Pumps are Not Running	In cases where the turbine driven FW pumps are tripped or are malfunctioning, it is currently necessary to manually isolate the pump discharge valves to prevent hotwell depletion and/or RPV overfill when RPV pressure is reduced. Failure to control the valves can make the hotwell unavailable as a suction source for other injection systems or flood the steam lines, which may lead to the unavailability of RCIC. Changing the system logic to automatically close the valves when the pumps trip or are not running would reduce the likelihood of uncontrolled injection (no RPV overfill from the Condensate/CB pumps when pressure is reduced).	LSCS Level 1 and 2 Importance Review	The LSCS specific cost estimate for implementation of this SAMA is $260,219 (S&L 2014).	Implementation cost is less than MACR. Retain for Phase II analysis.
11	Provide the Capability to Trip the FPS Pumps from the MCR	The reliability of the internal flood mitigation actions could be improved by providing the capability to trip the fire protection system pumps from the MCR. Currently, is it is necessary to for an operator to travel to the Lake Screen House to locally trip the fire protection pumps to eliminate that system's flow. Increasing the time margin for the operators to respond to the floods would improve the likelihood of preventing damage to critical ECCS equipment. It is assumed that this change would be accompanied by a procedure update that would include directions to remotely isolate valves 0FP070 and 0FP080 for Service Water isolation to ensure that the	LSCS Level 1 and 2 Importance Review	The cost of installing pump trip controls for the fire protection pumps in the Byron control room was estimated to be $217,415 (Exelon 2014).	Implementation cost is less than MACR. Retain for Phase II analysis.

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
		time benefits associated with the MCR pump control switches are fully realized.			
12	Cross-tie the HPCS and FW Injection Lines for ATWS Mitigation	The use of HPCS is not allowed for ATWS due to reactivity issues, but installing a cross-tie between the HPCS and FW injection lines would provide another means of supplying high pressure injection to the RPV in ATWS scenarios.	LSCS Level 1 and 2 Importance Review	The LSCS specific cost estimate for implementation of this SAMA is $4,401,674 (S&L 2014)	Implementation cost is less than MACR. Retain for Phase II analysis.
13	Not Used.	NA	NA	NA	
14	Provide a Portable DC Source to Support RCIC and SRV Operation	For scenarios with 125V DC bus faults, providing a means for a portable generator with DC output to supply 125V ESF DC distribution panel 1(2)11Y would support RCIC operation and long term SRV operation with Fire Protection System injection.	LSCS Level 1 and 2 Importance Review	Brunswick estimated the cost of a generator with DC output to be $489,277 (CPL 2004).	Implementation cost is less than MACR. Retain for Phase II analysis.

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
15	Tie RHRSW to the LPCS System for ISLOCA Mitigation	ISLOCA events are dominated by isolation failures in which there are no long term RPV makeup sources. Providing a hard pipe connection with manual valves between the RHRSW system and the LPCS system would provide a source of makeup to the RPV for cases in which RPV depressurization is available.	LSCS Level 1 and 2 Importance Review	The LSCS specific cost estimate for implementation of this SAMA is $1,366,982 (S&L 2014).	Implementation cost is less than MACR. Retain for Phase II analysis.
16	Provide Portable Fans for Alternate Room Cooling in the Core Standby Cooling System Vaults	Pump cubicle cooling fan or damper failures can result in the failure of the pumps in the Core Standby Cooling System vaults after heat up. Providing portable fans (and potentially temporary ductwork) could prevent failure by providing a temporary, alternate source of cubicle cooling. Room heat up calculations would be required as part of this effort to demonstrate that the portable fans could provide adequate cooling.	LSCS Level 1 and 2 Importance Review	Salem estimated the cost of providing portable fans for alternate room cooling to be $475,000 (PSEG 2009). Note: Includes portable fans and ducts as well as procedures and training, but not room heat up analysis.	Implementation cost is less than MACR. Retain for Phase II analysis.
17	Install ATWS Sized Reliable Containment Hard Pipe Vent	Containment venting is not credited as a heat removal path for ATWS scenarios because it is likely to result in severe conditions in the reactor building due to duct failure. The reliable containment hard pipe vent would provide a viable vent path for non-ATWS scenarios, but it is not designed to remove ATWS heat loads. Increasing the capacity of the reliable containment hard pipe vent would provide an additional means of containment heat removal in ATWS scenarios.	LSCS Level 1 and 2 Importance Review	The LSCS specific cost estimate for implementation of this SAMA is $17,900,000 (S&L 2014).	Implementation cost is greater than the MACR. Screened from further analysis.

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
18	Improve the Connection Between the Fire Protection and Feedwater Systems	For SBO cases with failure of RCIC, aligning the Fire Protection System to the Feedwater system using fire hoses cannot prevent core damage, primarily due to a lengthy alignment time. This time could be reduced by providing a hard pipe connection between the two systems. If a permanent connection between the systems is undesirable, a short, flexible connecting hose could potentially be maintained out of the flowpath provided that rapid alignment could be demonstrated.	LSCS Level 1 and 2 Importance Review	The LSCS specific cost estimate for implementation of this SAMA is $649,194 (S&L 2014).	Implementation cost is less than MACR. Retain for Phase II analysis.
19	Provide Remote Alignment Capability of RHRSW to the LPCS System for LOCA Mitigation	For some LOCA scenarios, CCF plugging of the ECCS suction strainers can fail all ECCS injection. Providing the operators with the ability to cross-tie the RHRSW system to the LPCS system from the MCR would provide a source of makeup to the RPV for cases in which RPV depressurization is available.	LSCS Level 1 and 2 Importance Review	Palisades estimated the cost of providing a remotely operated fire water to service water cross-tie to be $2,900,000 (NMC 2005). Note: Because this SAMA must mitigate LOCAs, rapid alignment is required and control from the MCR is considered to be a necessary feature of the design.	Implementation cost is less than MACR. Retain for Phase II analysis.

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
20	Improve Vacuum Breaker Reliability by Installing Redundant Valves in Each Line	For cases in which the vacuum breaker fails to reclose, the vapor suppression capability of the suppression pool is bypassed because an open pathway exists between the wetwell and the drywell. Events that result in a release of reactor inventory into the drywell can rapidly overpressurize containment without the condensing capability of the wetwell and cause a containment breach. Installation of redundant vacuum breakers would reduce the probability of failures that lead to suppression pool bypass. A potential drawback of adding a vacuum breaker in series with the existing vacuum breakers is that the "failure to open" probability of the path would be increased.	LSCS Level 1 and 2 Importance Review	Oyster Creek estimated a cost of $2 million to install an additional Vacuum breaker in the 7 torus to drywell lines to address this issue (AmerGen 2005). For LSCS, 4 vacuum breakers would be required in the drywell to wetwell pathways. The cost of implementation is assumed to be proportional to the number of vacuum breakers, which implies a cost of about $1,150,000 for LSCS.	Implementation cost is less than MACR. Retain for Phase II analysis.

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
21	Automatic ATWS Level Control System	For failure to scram conditions, early reduction in RPV level is important to limit the heat load sent to the containment, the reliability of which could be improved by automating the reduction of RPV level to just above -129 inches, ADS inhibit, and the "terminate and prevent" step (to disallow automatic RPV makeup from non-Feedwater sources). The logic would be required to actuate without operator interface and only actuate when the Feedwater system is available and providing makeup to the RPV. This would increase the time available for the operators to perform the other actions required early in ATWS scenarios, such as MSIV low level isolation logic bypass and SBLC initiation.	LSCS Level 1 and 2 Importance Review	The LSCS specific cost estimate for implementation of this SAMA is $1,481,002 (S&L 2014)	Implementation cost is less than MACR. Retain for Phase II analysis.
22	Hydrogen Igniters in Primary Containment	For cases in which containment venting is not adequate to prevent the buildup of combustible gases or when venting has failed, burning the combustible gases before they reach levels where detonation can cause containment failure is a means of reducing the consequences of severe accidents. Providing a means of power during SBO events would improve the capabilities of this system.	LSCS Level 1 and 2 Importance Review	McGuire estimated the cost of providing a generator to supply power to the existing igniters in SBO scenarios to be $205,000 (NRC 2002). For LSCS, the igniters themselves would be required in addition to an SBO power source, but this is used as a lower bound estimate for LSCS.	Implementation cost is less than MACR. Retain for Phase II analysis.

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
23	Enhance Fuel Pool Emergency Makeup Pump and Connection	For post core damage conditions, a system capable of injecting 1000 gpm or more to the RPV is estimated to be required to prevent reactor vessel meltthrough and core-concrete interactions that can fail the drywell. Replacing the existing Fuel Pool Emergency Makeup Pump with a higher pressure/higher flow pump and creating a permanent connection to the B RHR line could provide this capability. The capability would be similar to that of the RHRSW/LPCS cross-tie, but it makes use of a diverse system that is not currently considered in the PRA. This SAMA would also potentially be able to prevent core damage in many of the scenarios requiring water to prevent the RPV meltthrough and drywell failure events.	LSCS Level 1 and 2 Importance Review	This SAMA, like SAMA 15, requires a manually aligned cross-tie from a pump in the CSCS vault to a low pressure ECCS system for alternate injection. SAMA 23 also requires a new, higher capacity pump, but the $1,366,982 cost of SAMA 15 is used as a surrogate for this SAMA without escalation for an additional pump.	Implementation cost is less than MACR. Retain for Phase II analysis.
24	Provide Inter Division 4kV AC Cross-Tie Capability	The existing inter-unit cross-tie capability is valuable at LSCS, but additional flexibility could be gained by providing the capability to perform inter-divisional AC cross-ties in accident scenarios (e.g., 241Y to 242Y, or 242Y to 243C).	Industry Review/Fire Review	The LSCS specific cost estimate for implementation of this SAMA is $1,824,084 (S&L 2014).	Implementation cost is less than MACR. Retain for Phase II analysis.

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
25	Periodic Training on Water Hammer Scenarios Resulting from a False LOCA Signal	In transient scenarios, even with RHR operating in SPC mode, the DW will still reach 2 psig and a high DW pressure signal will register. When a consequential loss of offsite power occurs with the LOCA signal, this results in a load shed of the emergency buses while the EDGs start, during which time the discharge line of the previously running RHR train will drain to the suppression pool. When the RHR system is reloaded onto the emergency bus and the RHR pump starts, the discharge line will be empty and vulnerable to a water hammer event (PRA specific scenario). Incorporating training on this scenario into the Licensed Operator Cycle Training Plans would institutionalize it in a manner that would help ensure the operators maintain proficiency in addressing these types of scenarios and potentially improve the reliability of the actions required to prevent a water hammer event.	Industry Review	Cooper estimated the cost of providing enhanced ISLOCA training to be $112,000 (NPPD 2008). This is assumed to approximate the cost of providing water hammer training for LSCS.	Implementation cost is less than MACR. Retain for Phase II analysis.

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
26	Seismically Qualified Low Pressure RPV Makeup Capability	For seismic initiators that lead to SBOs and early failure of RCIC, aligning the Fire Protection System to the Feedwater system using fire hoses cannot currently prevent core damage. In order to mitigate these types of events, a hard-piped, seismically qualified low pressure injection pump with a seismically qualified suction source and power source would be required. This would ensure the system would be available in seismic events. In order to ensure it could be rapidly aligned for loss of injection cases, this SAMA includes the ability to align the system from the MCR. For power, a non-safety related, seismically qualified diesel generator would be required to energize the pump and to provide long term battery charger support to maintain RPV level instrumentation and SRV control for low pressure injection. The generator would be permanently installed outside of the Reactor Building and include remote start capability from the MCR to power the makeup pump. Alignment to the existing safety related battery chargers would be performed manually and possible within 4 hours. Ensuring that this capability would likely be available for seismic events with peak ground accelerations of up to 0.46g would address most of the estimated risk.	External Events Review	The LSCS specific cost estimate for implementation of this SAMA is $5,984,407 (S&L 2014).	Implementation cost is greater than the MACR. Screened from further analysis.

Table F.5-4
LSCS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate (per unit)	Phase 1 Baseline Disposition
27	Preclude Emergency Depressurization When RCIC is the Only Injection System Available and Provide Long Term DC Power	For cases where RCIC is the only injection system available, it would be possible to prevent core damage by changing the EOPs to allow RPV pressure to be maintained in the range of 150 to 250 psig even when containment temperature and pressure limits are violated. This would ensure the RCIC steam head is not lost in long term loss of containment heat removal scenarios. Providing a 480V AC generator to supply a battery charger would maintain plant instrumentation and control power, which would improve the reliability of this strategy.	External Events Review	Cooper estimated the cost of providing enhanced ISLOCA training to be $112,000 (NPPD 2008). This is assumed to approximate the cost of providing training for the long term use of RCIC without suppression pool cooling for LSCS. The cost of the 480V AC generator to support a battery charger was estimated by Ginna to be $400,000 (RG&E 2002). The total cost is sum of these components, or $512,000.	Implementation cost is less than MACR. Retain for Phase II analysis.

Table F.6-1
LSCS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
1	Install Reliable Hard Pipe Containment Vent	This is already a commitment for LSCS, but it has not yet been installed and is not modeled in the PRA. This SAMA, which will prevent vent path failure within the reactor building and will provide a means of safely operating the containment vent when normal support systems are unavailable (non-adverse environment for use of portable pneumatic supply or manual valve operation). This SAMA is used to track this enhancement in the analysis and to facilitate the interpretation of the results.	LSCS Level 1 and 2 Importance Review	Not Applicable: Implementation is planned independent of SAMA analysis. The phase 2 quantification results are documented in section F.6.1 to provide an estimate of the impact of the SAMA and to support sensitivity calculations in Section F.7.
2	Automate Suppression Pool Cooling Initiation	Suppression pool cooling initiation is a reliable action, but for non-LOCA events, automating SPC initiation on high suppression pool temperature could further improve the reliability of the containment heat removal function.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is positive and is classified as potentially "cost-beneficial".
3	Passive Vent Path	For loss of containment heat removal scenarios, the reliability of the containment venting function could be improved by installing a passive vent path. If the suppression chamber vent path were equipped with a rupture disk in parallel with the remotely operated vent path, a scrubbed release path would be available to prevent containment failure in the event that normal venting fails. The rupture disk failure pressure would have to be less than the ultimate containment strength to ensure it would rupture before the containment, but consideration could also be given to a lower pressure to ensure SRVs could remain operable to support low pressure injection in loss of containment heat removal cases. Effectiveness is contingent on the implementation of the hard pipe vent.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is negative and is classified as not "cost-beneficial".

Table F.6-1
LSCS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
4	Install a Keylock MSIV Low Level Isolation Bypass Switch	Operator errors are some of the largest contributors to ATWS scenarios, which are complicated by the short times available for response. One of the more time limited actions in these scenarios is the action to bypass the MSIV low level isolation signal, which is currently an action that requires the installation of jumpers. Providing a switch in the MCR that would bypass the isolation logic would simplify the bypass action and provide more time margin for the power/level control actions for these scenarios. In order to improve the effectiveness of this enhancement, the EOP step that directs RPV level reduction should be modified such that the operators immediately lower level to a control band above the MSIV closure setpoint and then include a decision point, including bypassing interlock, before lowering level further.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is negative and is classified as not "cost-beneficial".
5	Automate SBLC Initiation	ATWS events rely on timely initiation of the SBLC system for mitigation. A potential means of improving the reliability of this function would be to automate system initiation, as is that case at Limerick Generation Station.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is negative and is classified as not "cost-beneficial".
6	Create ECCS Suction Strainer Backflush Capability with RHRSW	For some LOCA contributors, common cause plugging of the ECCS suction strainers fails makeup/heat removal. Connecting the RHRSW system to the RHR pump suction line upstream of the F004A/B valves could provide a means of backflushing the system in conjunction with steps to close the F004A/B valves during the backflush.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is negative and is classified as not "cost-beneficial".

Table F.6-1
LSCS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
7	Water Hammer Prevention	Alter the LOCA signal logic to require both high drywell pressure AND low water level for initiation. This will prevent LOCA signals in transient scenarios where high DW pressure alone can cause consequential LOOP events and drain the discharge line of an RHR train running in SPC mode (PRA specific scenario). This could also have the added benefit of simplifying the operators' response to loss of offsite power events where the LOOP signal has caused the EDGs to start and load and an ECCS signal is subsequently received due to loss of containment cooling (high drywell pressure). In this LOOP-delayed LOCA scenario, the operators are required to take many actions to handle the automatic actuations that occur due to the LOCA signal. This scenario is not specifically modeled in the PRA.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is negative and is classified as not "cost-beneficial".
8	Obtain a 480V AC Portable Generator to Supply the 125V DC Battery Chargers and Proceduralize its Use	For long term SBO scenarios, the hardened containment vent that LSCS is committed to install will provide a means of containment heat removal, but the battery life is currently assumed to be limited to about 7 hours in the PRA model. After battery depletion, the SRVs will close and the RPV will re-pressurize and prevent injection with a low pressure system, such as the fire protection system. Use of a portable generator to provide power to the 125V DC battery chargers would provide a means of maintaining the SRVs open, energize critical instrumentation, and ensure RPV pressure remains low enough for use of low pressure alternate makeup systems.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is negative and is classified as not "cost-beneficial".

Table F.6-1
LSCS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
9	Develop Flood Zone Specific Procedures	The reliability of the internal flood mitigation actions could be improved by developing location and system specific flood response procedures. For example, for fire protection floods in the reactor building, developing procedures that direct the isolation of the FP070 and FP080 valves could significantly reduce the time required to terminate reactor building floods from the fire protection system. Increasing the time margin for the operators to respond to the floods would improve the likelihood of preventing damage to critical ECCS equipment.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is positive and is classified as potentially "cost-beneficial".
10	Change the Logic to Close the Turbine Driven Feedwater Pump Discharge Valves When the Pumps are Not Running	In cases where the turbine driven FW pumps are tripped or are malfunctioning, it is currently necessary to manually isolate the pump discharge valves to prevent hotwell depletion and/or RPV overfill when RPV pressure is reduced. Failure to control the valves can make the hotwell unavailable as a suction source for other injection systems or flood the steam lines, which may lead to the unavailability of RCIC. Changing the system logic to automatically close the valves when the pumps trip or are not running would reduce the likelihood of uncontrolled injection (no RPV overfill from the Condensate/CB pumps when pressure is reduced).	LSCS Level 1 and 2 Importance Review	This SAMA's net value is positive and is classified as potentially "cost-beneficial".
11	Provide the Capability to Trip the FPS Pumps from the MCR	The reliability of the internal flood mitigation actions could be improved by providing the capability to trip the fire protection system pumps from the MCR. Currently, is it is necessary to for an operator to travel to the Lake Screen House to locally trip the fire protection pumps to eliminate that system's flow. Increasing the time margin for the operators to respond to the floods would improve the likelihood of preventing damage to critical ECCS equipment. It is assumed that this change would be accompanied by a procedure update that would include directions to remotely isolate valves 0FP070 and 0FP080 for Service Water isolation to ensure that the time benefits	LSCS Level 1 and 2 Importance Review	This SAMA's net value is negative and is classified as not "cost-beneficial".

Table F.6-1
LSCS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
		associated with the MCR pump control switches are fully realized.		
14	Provide a Portable DC Source to Support RCIC and SRV Operation	For scenarios with 125V DC bus faults, providing a means for a portable generator with DC output to supply 125V ESF DC distribution panel 1(2)11Y would support RCIC operation and long term SRV operation with Fire Protection System injection.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is negative and is classified as not "cost-beneficial".
15	Tie RHRSW to the LPCS System for ISLOCA Mitigation	ISLOCA events are dominated by isolation failures in which there are no long term RPV makeup sources. Providing a hard pipe connection with manual valves between the RHRSW system and the LPCS system would provide a source of makeup to the RPV for cases in which RPV depressurization is available.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is positive and is classified as potentially "cost-beneficial".
16	Provide Portable Fans for Alternate Room Cooling in the Core Standby Cooling System Vaults	Pump cubicle cooling fan or damper failures can result in the failure of the pumps in the Core Standby Cooling System vaults after heat up. Providing portable fans (and potentially temporary ductwork) could prevent failure by providing a temporary, alternate source of cubicle cooling. Room heat up calculations would be required as part of this effort to demonstrate that the portable fans could provide adequate cooling.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is positive and is classified as potentially "cost-beneficial".

Table F.6-1
LSCS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
18	Improve the Connection Between the Fire Protection and Feedwater Systems	For SBO cases with failure of RCIC, aligning the Fire Protection System to the Feedwater system using fire hoses cannot prevent core damage, primarily due to a lengthy alignment time. This time could be reduced by providing a hard pipe connection between the two systems. If a permanent connection between the systems is undesirable, a short, flexible connecting hose could potentially be maintained out of the flowpath provided that rapid alignment could be demonstrated.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is negative and is classified as not "cost-beneficial".
19	Provide Remote Alignment Capability of RHRSW to the LPCS System for LOCA Mitigation	For some LOCA scenarios, CCF plugging of the ECCS suction strainers can fail all ECCS injection. Providing the operators with the ability to cross-tie the RHRSW system to the LPCS system from the MCR would provide a source of makeup to the RPV for cases in which RPV depressurization is available.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is positive and is classified as potentially "cost-beneficial".
20	Improve Vacuum Breaker Reliability by Installing Redundant Valves in Each Line	For cases in which the vacuum breaker fails to reclose, the vapor suppression capability of the suppression pool is bypassed because an open pathway exists between the wetwell and the drywell. Events that result in a release of reactor inventory into the drywell can rapidly overpressurize containment without the condensing capability of the wetwell and cause a containment breach. Installation of redundant vacuum breakers would reduce the probability of failures that lead to suppression pool bypass. A potential drawback of adding a vacuum breaker in series with the existing vacuum breakers is that the "failure to open" probability of the path would be increased.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is negative and is classified as not "cost-beneficial".

Table F.6-1
LSCS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
21	Automatic ATWS Level Control System	For failure to scram conditions, early reduction in RPV level is important to limit the heat load sent to the containment, the reliability of which could be improved by automating the reduction of RPV level to just above -129 inches, ADS inhibit, and the "terminate and prevent" step (to disallow automatic RPV makeup from non-Feedwater sources). The logic would be required to actuate without operator interface and only actuate when the Feedwater system is available and providing makeup to the RPV. This would increase the time available for the operators to perform the other actions required early in ATWS scenarios, such as MSIV low level isolation logic bypass and SBLC initiation.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is negative and is classified as not "cost-beneficial".
22	Hydrogen Igniters in Primary Containment	For cases in which containment venting is not adequate to prevent the buildup of combustible gases or when venting has failed, burning the combustible gases before they reach levels where detonation can cause containment failure is a means of reducing the consequences of severe accidents. Providing a means of power during SBO events would improve the capabilities of this system.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is negative and is classified as not "cost-beneficial".
23	Enhance Fuel Pool Emergency Makeup Pump and Connection	For post core damage conditions, a system capable of injecting 1000 gpm or more to the RPV is estimated to be required to prevent reactor vessel meltthrough and core-concrete interactions that can fail the drywell. Replacing the existing Fuel Pool Emergency Makeup Pump with a higher pressure/higher flow pump and creating a permanent connection to the B RHR line could provide this capability. The capability would be similar to that of the RHRSW/LPCS cross-tie, but it makes use of a diverse system that is not currently considered in the PRA. This SAMA would also potentially be able to prevent core damage in many of the scenarios requiring water to prevent the RPV meltthrough and drywell failure events.	LSCS Level 1 and 2 Importance Review	This SAMA's net value is positive and is classified as potentially "cost-beneficial".

Table F.6-1
LSCS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
24	Provide Inter Division 4kV AC Cross-Tie Capability	The existing inter-unit cross-tie capability is valuable at LSCS, but additional flexibility could be gained by providing the capability to perform inter-divisional AC cross-ties in accident scenarios (e.g., 241Y to 242Y, or 242Y to 243C).	Industry Review/Fire Review	This SAMA's net value is negative and is classified as not "cost-beneficial".
25	Periodic Training on Water Hammer Scenarios Resulting from a False LOCA Signal	In transient scenarios, even with RHR operating in SPC mode, the DW will still reach 2 psig and a high DW pressure signal will register. When a consequential loss of offsite power occurs with the LOCA signal, this results in a load shed of the emergency buses while the EDGs start, during which time the discharge line of the previously running RHR train will drain to the suppression pool. When the RHR system is reloaded onto the emergency bus and the RHR pump starts, the discharge line will be empty and vulnerable to a water hammer event (PRA specific scenario). Incorporating training on this scenario into the Licensed Operator Cycle Training Plans would institutionalize it in a manner that would help ensure the operators maintain proficiency in addressing these types of scenarios and potentially improve the reliability of the actions required to prevent a water hammer event.	Industry Review	This SAMA's net value is negative and is classified as not "cost-beneficial".
27	Preclude Emergency Depressurization When RCIC is the Only Injection System Available and Provide Long Term DC Power	For cases where RCIC is the only injection system available, it would be possible to prevent core damage by changing the EOPs to allow RPV pressure to be maintained in the range of 150 to 250 psig even when containment temperature and pressure limits are violated. This would ensure the RCIC steam head is not lost in long term loss of containment heat removal scenarios. Providing a 480V AC generator to supply a battery charger would maintain plant instrumentation and control power, which would improve the reliability of this strategy.	External Events Review	This SAMA's net value is negative and is classified as not "cost-beneficial".

Table F.7-1
MACCS2 ECONOMIC PARAMETERS INPUTS FOR LASCHR3

Variable	Description	Base Case Value	LASCHR3
DPRATE[(1)]	Property depreciation rate (per yr)	0.20	0.20
DSRATE[(2)]	Investment rate of return (per yr)	0.07	0.07
EVACST[(3)]	Daily cost for a person who has been evacuated ($/person-day)	57.51	115.02
RELCST[(3)]	Daily cost for a person who is relocated ($/person-day)	57.51	115.02
POPCST[(3)]	Population relocation cost ($/person)	10,650	21,300
TIMDEC[(1)]	Decontamination time for each level[(5)]	2 & 4 months	2 & 12 months
CDFRM0[(3)]	Cost of farm decontamination for two levels of decontamination ($/hectare)[(5)]	1,198 2,663	2,396 5,326
CDNFRM[(3)]	Cost of non-farm decontamination per resident person for two levels of decontamination ($/person)[(5)]	6,390 17,040	12,780 34,080
DLBCST[(3)]	Average cost of decontamination labor ($/man-year)	74,550	149,100
TFWKF[(1)]	Time workers spend in Farm land contaminated areas[(5)]	1/10 1/3	1/4 1/4
TFWKNF[(1)]	Time workers spend in Non-Farm land contaminated areas[(5)]	1/3 1/3	1/4 1/4
VALWF0[(4)]	Weighted average value of farm wealth ($/hectare)	11,937	11,937
VALWNF[(4)]	Weighted average value of non-farm wealth ($/person)	283,637	283,637

1 Uses NUREG/CR-4551 value (NRC 1990b).

2 DSRATE based on NUREG/BR-0058 (NRC 2004a).

3 These parameters use the NUREG/CR-4551 value (NRC 1990b), updated to July 2013 using the CPI.

4 VALWF0 and VALWNF are based on the 2007 Census of Agriculture (USDA 2009), Bureau of Labor Statistics (BLS 2013) and Bureau of Economic Analysis (BEA 2013) data, updated to July 2013 using the CPI for the counties within 50 miles.

5 Two decontamination levels are modeled. The first value is associated with a dose reduction factor of 3. The second value is associated with a dose reduction factor of 15.

F.10 FIGURES

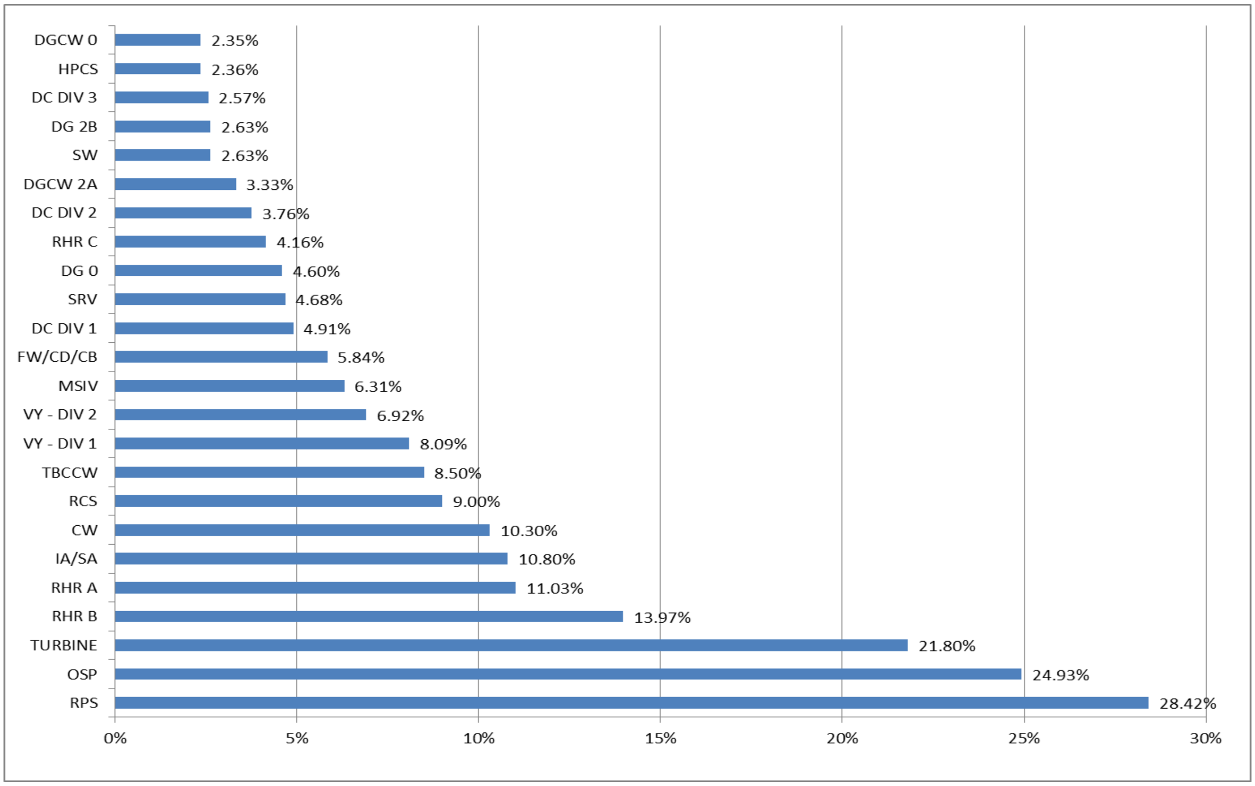

Figure F.2-1
LS213A System, Train, Component Fussell-Vesely Importance Measure

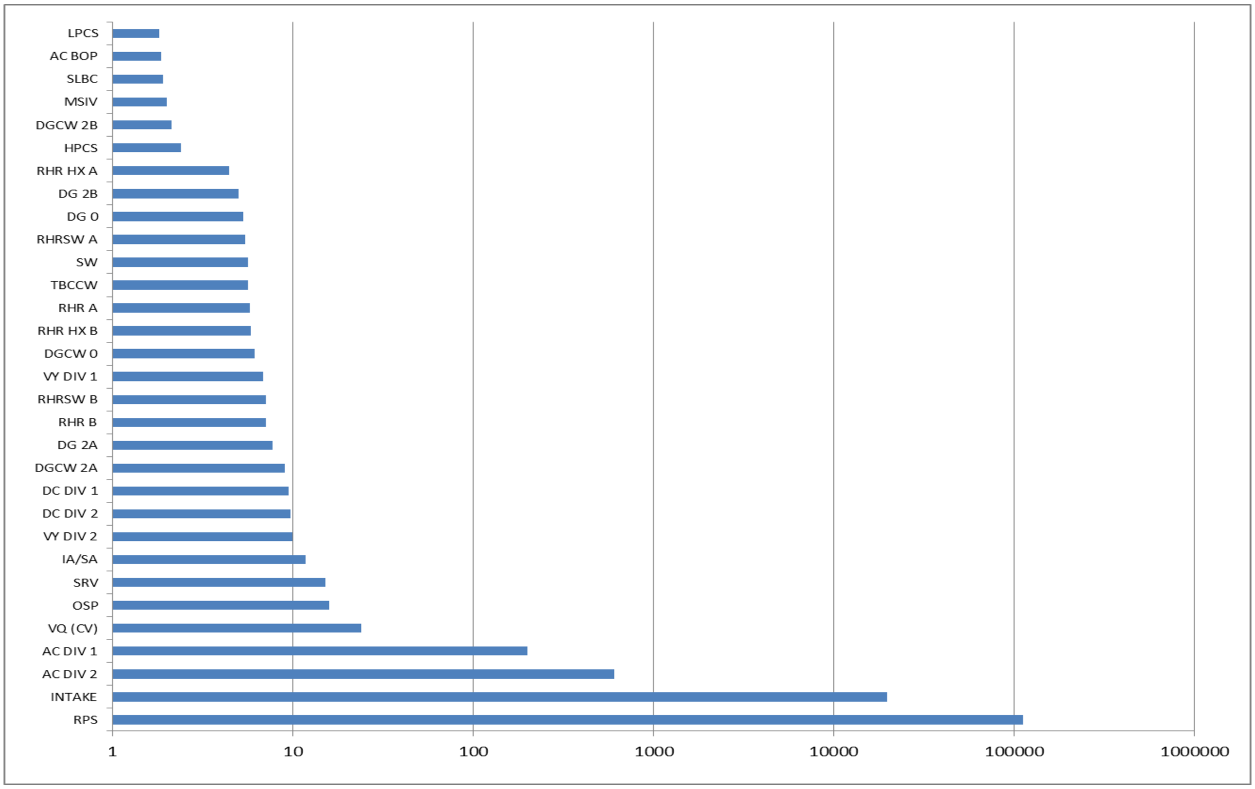

Figure F.2-2
LS213A System, Train, Component RAW Importance Measure

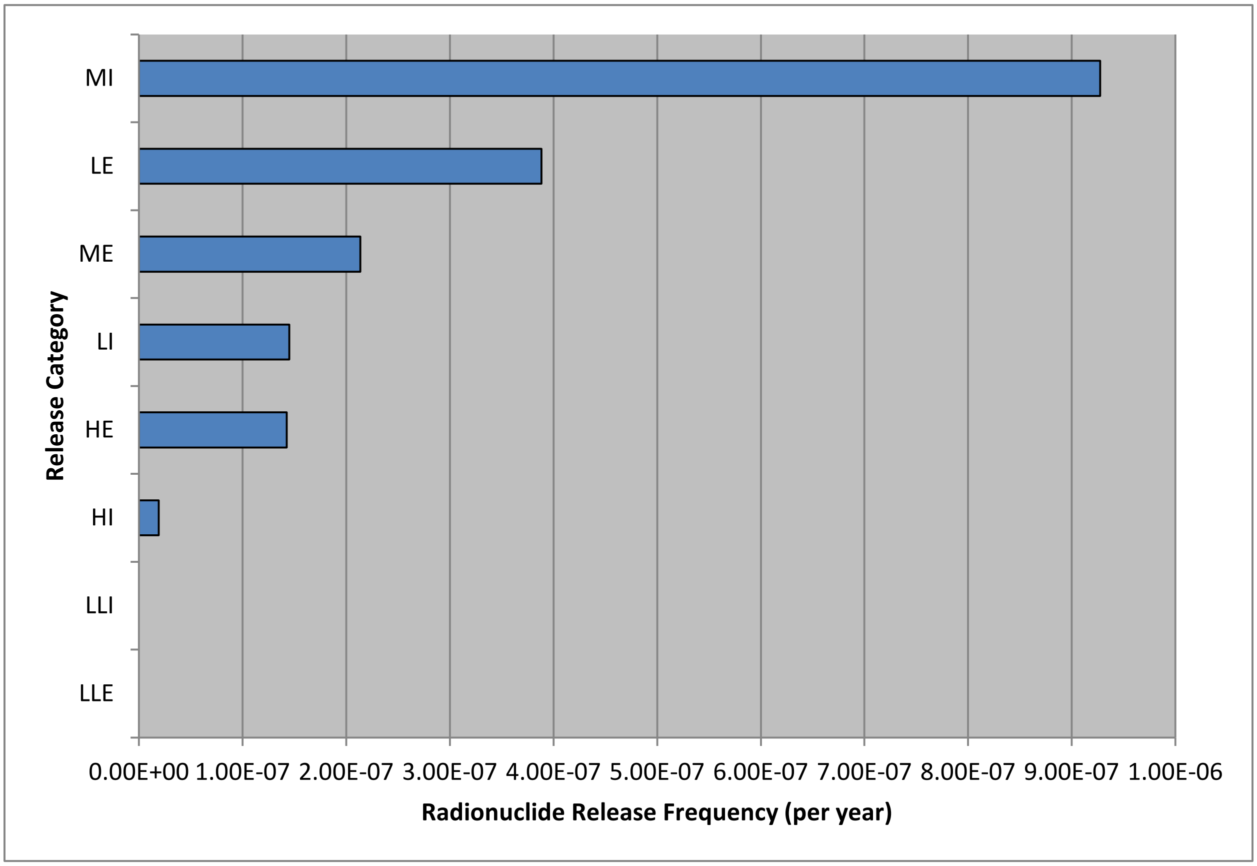

Figure F.2-3
Summary of Release Magnitudes
Summary of LSCS Level 2 Release Categories (/cr-yr)

Legend:

HE – High Early

HI – High Intermediate

ME – Medium Early

MI – Medium Intermediate

LE – Low Early

LI – Low Intermediate

LLE – Low-low Early

LLI – Low-low Intermediate

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