# 5.0 ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION

**NRC**

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

When applying to the U.S. Nuclear Regulatory Commission (NRC) for license renewal, licensees of domestic nuclear power plants must provide an application that includes an Environmental Report (ER) (10 CFR 54.23). NRC regulations, 10 CFR 51, prescribe the environmental report content and identify the specific analyses the applicant must perform. In an effort to perform the environmental review efficiently and effectively, NRC has resolved most of the environmental issues generically (designated as Category 1 issues), but requires an applicant's analysis of all the remaining applicable issues (designated as Category 2 issues).

While NRC regulations do not require an applicant's ER to contain analyses of the impacts of generically resolved environmental issues [10 CFR 51.53(c)(3)(i)], the regulations do require that an applicant identify any new and significant information of which the applicant is aware [10 CFR 51.53(c)(3)(iv)]. This requirement serves to alert NRC staff to such pertinent information, so the staff can determine whether to seek NRC'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 its conclusions in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS)* (NRC 1996).

Nuclear Management Company, Inc. (NMC) expects that new and significant information would include:

- Information that identifies a "significant" environmental issue the GEIS does not cover and is not codified in the regulation, or

- Information not covered in the GEIS analyses that leads to an impact finding different from that codified in the regulation.

NRC does not define the term "significant." For the purpose of its review, NMC used guidance available in Council on Environmental Quality (CEQ) regulations. The National Environmental Policy Act (NEPA) 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 NEPA requirements as they apply to license renewal (10 CFR 51.10). CEQ guidance provides that federal agencies should prepare environmental impact statements for actions that would significantly affect the environment (40 CFR 1502.3), 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). NMC expects that moderate or large impacts, as defined by NRC, would be “significant.” NMC presents NRC definitions of “Moderate” and “Large” impacts in Section 4.1.2 of this environmental report.

NMC prepared this Prairie Island Nuclear Generating Plant (PINGP) ER in accordance with NRC regulations at 10 CFR 51.53(c). In response to 10 CFR 51.53(c)(3)(iv), NMC implemented a process for identifying new and significant information in preparation of this environmental report for PINGP License Renewal application. The process was directed by the License Renewal Environmental Project Manager and included the following actions:

1. Assembly of an investigative team comprised of key representatives of NMC, Xcel Energy, and Tetra Tech NUS, Inc. to support preparation of the environmental report and to conduct the new and significant information review (NMC and Xcel Energy representatives consisted of individuals specifically knowledgeable about plant systems, the site environment, and plant environmental issues);

2. Interviews with subject matter experts from NMC and Xcel Energy related to the conclusions in the GEIS as they relate to PINGP;

3. Review of the environmental management programs, permits, procedures, and practices in place for PINGP to understand their scope and effectiveness for managing potential impacts of PINGP operations and/or as mechanisms for staff to become aware of new and significant information;

4. Review of internal and external documents and records related to environmental aspects of PINGP, its environs, and its associated transmission lines, including but not limited to, environmental assessments and monitoring reports, procedures, and other management controls, compliance history reports, and environmental resource plans and data;

5. Correspondence with state and federal regulatory agencies to determine agency environmental concerns related to PINGP operations;

6. Interface with nuclear power industry representatives to ensure current knowledge of events at other plants with potential to affect environmental issues;

7. Review of other license renewal application submittals for pertinent issues;

8. Crediting the oversight provided by inspections of plant facilities by state and federal regulatory agencies; and

9. Correspondence with tribal governments, including the Prairie Island Indian Community, to determine environmental concerns related to PINGP operations.

Information obtained as a result of these activities, including information from state and local agencies and tribal governments, was evaluated with respect to the criteria described above. As a result of this process, NMC is not aware of any new and significant information regarding the environmental impacts of PINGP license renewal.

In addition to this process, NMC notes that state and federal regulatory agencies routinely inspect PINGP facilities and records as part of their oversight of the plant and its operation and to ensure that permit conditions are met. These inspections (and less frequent permit reviews) have identified no new and significant information.

## 5.1 REFERENCES

NRC (U.S. Nuclear Regulatory Commission). 1996. *Public Comments on the Proposed 10 CFR 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response.* Volumes 1 and 2. NUREG-1529. Washington, DC. May.

# 6.0 SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS

## 6.1 LICENSE RENEWAL IMPACTS

Nuclear Management Company (NMC) has reviewed the environmental impacts of renewing the Prairie Island Nuclear Generating Plant (PINGP) operating licenses and has concluded that impacts would be SMALL and would not require mitigation. This Environmental Report documents the basis for the conclusion. Section 4.1.1 incorporates by reference U.S. Nuclear Regulatory Commission (NRC) findings for the 57 Category 1 issues that apply to PINGP, all of which have impacts that are SMALL (Table A-1, Attachment A). Sections 4.2 through 4.17 analyze Category 2 issues, all of which are either not applicable or have impacts that would be SMALL. Table 6-1 identifies the impacts that PINGP license renewal would have on resources associated with Category 2 issues.

## 6.2 MITIGATION

**NRC**

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

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

Impacts of license renewal would be SMALL and would not require mitigation. Current operations include monitoring activities that would continue during the license renewal term. NMC performs routine monitoring to ensure the safety of workers, the public, and the environment. These activities include the biological monitoring program, radiological environmental monitoring program, air monitoring, effluent chemistry monitoring, and effluent toxicity testing. In addition, focused surveys for sensitive resources (e.g., threatened or endangered species) are conducted for onsite land-disturbing activities. These monitoring programs ensure that the plant's permitted emissions and discharges are within regulatory limits and any unusual or off-normal emissions/discharges would be quickly detected, mitigating potential impacts.

## 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 NRC findings for applicable Category 1 issues, including discussions of any unavoidable adverse impacts (Table A-1, Attachment A). NMC examined 21 Category 2 issues and identified the following unavoidable adverse impacts of license renewal:

- Some larval, juvenile, and adult fish are impinged on the traveling screens at the Intake Screenhouse, but most are returned to the Mississippi River unharmed via the fish return line. Based on studies conducted in the 1980s, gizzard shad, channel catfish, and freshwater drum are the species most often impinged on coarse-mesh intake screens, which are in service from September 1 through March 31. Freshwater drum eggs and larvae, Cyprinid larvae, gizzard shad larvae, and carp larvae (and other early life stages) are most often impinged on fine-mesh intake screens, which are in service from April 1 through August 31.
- Some larval fish are entrained at the Intake Screenhouse, but flow (withdrawal) restrictions and fine mesh screens substantially reduce the total number. Based on a 1975 study, most eggs entrained are those of freshwater drum, while most young fish entrained are shiners, gizzard shad, suckers, white bass, carp, and freshwater drum.
- NMC expects that existing "surge" capabilities would enable PINGP to perform the increased surveillance, monitoring, inspections, testing, trending, and recordkeeping (SMITTR) workload through the addition of no more than two staff members. However, for the purpose of this analysis, NMC has assumed that license renewal could necessitate adding as many as 60 staff. The assumed addition of 60 direct workers to Dakota and Goodhue counties, Minnesota and Pierce County, Wisconsin, where approximately 83 percent of the PINGP workforce resides, could result in small impacts to housing availability, public water supply, offsite land use, and transportation infrastructure (see Sections 4.11, 4.12, 4.14, and 4.15).

## 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 PINGP for the license renewal term will result in irreversible and irretrievable resource commitments, including the following:

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

These irreversible and irretrievable resource commitments are manageable and low impact.

## 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 the PINGP site was established with the decision to construct the plant. The Final Environmental Statement related to the Prairie Island Nuclear Generating Plant (AEC 1973) evaluated the impacts of constructing and operating PINGP in Goodhue County, Minnesota. Short-term use of natural resources would include land and water. Much of the 560-acre site was under cultivation before its acquisition. Approximately 240 acres were disturbed and modified by plant construction activities, and 60 acres are occupied by plant structures and related facilities. Because Northern States Power (NSP) was able to take advantage of existing transmission corridors, it was only necessary to acquire 33 miles of new right-of-way. Dredging of the cooling water system canals resulted in some disruption of aquatic environments in a limited area of the river. The cooling towers historically produced some localized fogging and icing, particularly during winter months, but are now used primarily in spring and summer (AEC 1973).

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

NMC notes that the current balance between short-term use and long-term productivity of the environment at the PINGP site is now well-established and can be expected to remain essentially unchanged by renewal of the operating license and extended operation of PINGP. Extended operation of PINGP would postpone restoration of the site and its potential availability for uses other than electric power generation. It would also result in other short-term impacts on the environment, all of which have been determined to be small on the basis of NRC's evaluation in the Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) and NMC's evaluation in this Environmental Report (ER).

# TABLE 6-1
# ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL AT PINGP

| No. | Issue | Environmental Impact |
|---|---|---|
| | **Surface Water Quality, Hydrology, and Use (for all plants)** | |
| 13 | Water use conflicts (plants with cooling ponds or cooling towers using makeup water from a small river with low flow) | SMALL. Consumptive use represents less than 1 percent of the mean annual flow of the Mississippi River and would have little or no effect on the Mississippi River and its riparian ecological communities. |
| | **Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)** | |
| 25 | Entrainment of fish and shellfish in early life stages | SMALL. PINGP has a current NPDES permit which constitutes compliance with CWA Section 316(b) requirements to provide best technology available to minimize entrainment. |
| 26 | Impingement of fish and shellfish | SMALL. PINGP has a current NPDES permit which constitutes compliance with CWA Section 316(b) requirements to provide best technology available to minimize impingement. |
| 27 | Heat shock | SMALL. PINGP discharges meet state water quality standards and have very little impact on local aquatic life. |
| | **Groundwater Use and Quality** | |
| 33 | Groundwater use conflicts (potable and service water, and dewatering; plants that use > 100 gpm) | SMALL. Drawdown through the current license is expected to be 0.4 feet at the nearest offsite well and there would be no additional drawdown during the license renewal period. |
| 34 | Groundwater use conflicts (plants using cooling towers or cooling ponds withdrawing makeup water from a small river) | SMALL. PINGP consumptive use has little impact on Mississippi River flow, even during low flow conditions, and therefore have little effect on recharge to the alluvial aquifer. |
| 35 | Groundwater use conflicts (Ranney wells) | NONE. This issue does not apply because PINGP does not use Ranney wells. |
| 39 | Groundwater quality degradation (cooling ponds at inland sites) | NONE. This issue does not apply because PINGP does not use cooling ponds. |
| | **Terrestrial Resources** | |
| 40 | Refurbishment impacts | SMALL. Refurbishment activities would occur in an area that is devoid of important plant and animal habitats. Peregrine falcons nest at PINGP and have presumably become habituated to activities at the plant. |
| | **Threatened or Endangered Species** | |
| 49 | Threatened or endangered species | SMALL. Several federally-listed species are found in the general vicinity of PINGP, but none is believed to be jeopardized by plant operation. NMC has no plans to change plant operations and transmission line maintenance practices. |

## TABLE 6-1 (CONTINUED) ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL AT PINGP

| No. | Issue | Environmental Impact |
|---|---|---|
| | | **Air Quality** |
| 50 | Air quality during refurbishment (non-attainment and maintenance areas) | SMALL. Refurbishment activities would be of short duration. Goodhue County is in attainment for all criteria pollutants. Fugitive dust resulting from construction activities would be minimal. Impacts from exhaust emissions would not impact nearby maintenance areas. |
| | | **Human Health** |
| 57 | Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river) | SMALL. PINGP periodically chlorinates the circulating water system to control microbiological organisms in accordance with the NPDES permit, thereby preventing migration of these organisms to the Mississippi River. |
| 59 | Electromagnetic fields, acute effects (electric shock) | SMALL. The largest modeled induced current under the PINGP lines is less than the 5 milliampere limit. Therefore, the lines conform to the NESC provisions for preventing electric shock from induced current. |
| | | **Socioeconomics** |
| 63 | Housing impacts | SMALL. NRC concluded that housing impacts would be SMALL in medium and high population areas having no growth control measures. PINGP is located in a high population area with no growth control measures. |
| 65 | Public services: public utilities | SMALL. Excess water capacity in the region of influence (ROI) is more than sufficient to handle the temporary refurbishment workforce and the permanent license renewal population growth. |
| 66 | Public services: education (refurbishment) | SMALL. Anecdotal evidence from the 2004 steam generator replacement suggests that the majority of the refurbishment workforce would not relocate families to the plant site region for a project of this short duration, having little impact on school enrollment. |
| 68 | Offsite land use (refurbishment) | SMALL. A refurbishment workforce of 750 would represent less than a 5 percent increase in the population of Goodhue County and an even smaller percent increase in the populations of the largest cities within the 50-mile region. |
| 69 | Offsite land use (license renewal term) | SMALL. No changes in offsite land use are expected to occur as a result of license renewal. |
| 70 | Public services: transportation | SMALL. Increased traffic flow during shift changes is expected during refurbishment activities, but the capacities of area roads are more than adequate. The increase in traffic flow as a result of license renewal would most likely be unnoticeable. |
| 71 | Historic and archeological resources | SMALL. License renewal would have little or no effect on historic or archeological resources. Refurbishment may require limited ground-disturbing activities, but only in previously-disturbed areas. In addition, PINGP has an excavation procedure in place to protect potential archeological, historical, or cultural resources. |

## TABLE 6-1 (CONTINUED)
## ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL AT PINGP

| No. | Issue | Environmental Impact |
|---|---|---|
| | | **Postulated Accidents** |
| 76 | Severe accidents | SMALL. NMC identified 2 potentially cost beneficial SAMAs for each unit; however none were related to aging management. NMC will evaluate these enhancements for future implementation. |

## 6.6 REFERENCES

AEC (U.S. Atomic Energy Commission). 1973. *Final Environmental Statement related to Prairie Island Nuclear Generating Plant.* Northern States Power Company. Docket Nos. 50-282 and 50-306. Directorate of Licensing. Washington, DC. May.

# 7.0 ALTERNATIVES TO THE PROPOSED ACTION

**NRC**

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

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

**"While many methods are available for generating electricity, and a huge number of combinations or mixes can be assimilated to meet a defined generating requirement, such expansive consideration would be too unwieldy to perform given the purposes of this analysis. Therefore, NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable…" (NRC 1996a)**

**"…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)**

The U.S. Nuclear Regulatory Commission (NRC) considers the environmental impacts of the proposed action (i.e., license renewal) and alternatives to the proposed action in accordance with its National Environmental Policy Act (NEPA) implementing regulations when deciding whether to approve renewal of an applicant's operating license [10 CFR 51.95(c)]. In this chapter, Nuclear Management Company, LLC (NMC) identifies reasonable alternatives to renewal of the Prairie Island Nuclear Generating Plant (PINGP) operating licenses and presents its evaluation of associated environmental impacts. This chapter also includes descriptions of alternatives NMC considered but determined to be unreasonable to consider in detail, and associated supporting rationale.

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

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

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

Therefore, NMC generally structured the analyses to provide enough information to support NRC decision-making by demonstrating whether an alternative would have a smaller, comparable, or greater environmental impact than the proposed action. This approach is consistent with the Council on Environmental Quality regulations, which provide that the consideration of alternatives (including the proposed action) be adequately addressed so reviewers may evaluate their comparative merits [40 CFR 1502.14(b)].

NMC characterizes environmental impacts in this chapter using the same definitions of SMALL, MODERATE, and LARGE used in Chapter 4 of this Environmental Report (ER) and by NRC in its Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996a). In Chapter 8, NMC presents a summary comparison of environmental impacts of the proposed action and alternatives.

## 7.1 NO-ACTION ALTERNATIVE

NMC considers the no-action alternative addressed in this ER to be a scenario in which NRC does not renew the current PINGP operating licenses, PINGP ceases operation and is decommissioned, and Xcel Energy or others take appropriate action to replace or compensate for the loss of generating capacity. Section 7.1.1 addresses potential environmental impacts of terminating operations and decommissioning exclusive of actions to replace power from PINGP. NMC discusses alternatives for replacing or compensating for the loss of generating capacity in Section 7.2 of this ER.

### 7.1.1 TERMINATING OPERATIONS AND DECOMMISSIONING

In the event the NRC does not renew the PINGP operating licenses, NMC assumes the units would be operated until their current licenses expire in 2013 and 2014, then decommissioned in accordance with NRC requirements. Decommissioning denotes the safe removal from service of a nuclear generating facility and the reduction of residual radioactivity to a level that permits release of the property for unrestricted or restricted use, and termination of the license [10 CFR 50.2]. NMC assumes PINGP would be decommissioned for unrestricted use. The two decommissioning options typically selected for U.S. reactors are (NRC 2002a):

- immediate decontamination and dismantlement (DECON), and
- safe storage of the stabilized and defueled facility for a period of time followed by decontamination and dismantlement (SAFSTOR).

Regardless of the option chosen, decommissioning methods would be described in the post-shutdown decommissioning activities report, which must be submitted to NRC within two years following cessation of operations [10 CFR 50.82(a)(4)]. Decommissioning activities, in accordance with 10 CFR 50.82(a)(3), must be completed within 60 years after operations cease (NRC 1996a). Related NRC requirements ensure that the decommissioning activities, when defined, would be subject to required environmental reviews in accordance with NEPA [10 CFR 50.82, 10 CFR 51.53(d)].

In the GEIS, the NRC provides a summary of decommissioning activities, generic environmental impacts of the decommissioning process, and an evaluation of potential changes in impact that could result from deferring decommissioning for up to 20 years (NRC 1996a). This GEIS analysis is based on a 1988 generic environmental impact evaluation of decommissioning, NUREG-0586 (NRC 1988), which uses the 1,175-megawatt electric (MWe) Trojan Nuclear Plant, as representative of decommissioning activities for pressurized water reactor, the reactor type used at PINGP (Section 3.1.1 of this ER).

The NRC concluded from the GEIS generic evaluation that decommissioning would have SMALL impacts with respect to radiation dose, waste management, air quality, water quality, socioeconomic impacts and ecological resources, and that impacts would not be significantly greater as a result of the proposed action (NRC 1996a, 10 CFR 51).

Considering the information presented in the GEIS and the fact that the PINGP has smaller reactors than the GEIS reference plant, NMC considers the NRC's generic evaluation and associated conclusions in the GEIS bound PINGP for purposes of this ER. The NRC has updated the 1988 generic environmental impact evaluation of decommissioning on which the GEIS is based. This update, Supplement 1 to NUREG-0586, expanded the original analysis by addressing impacts of dismantling structures, systems, and components required to operate the reactor and also considered characteristics of plants currently operating in the U.S. (NRC 2002a). Of the 23 environmental issues evaluated in this updated analysis, the NRC concluded that the following were site-specific: impacts on land use from offsite activities; impacts on aquatic and terrestrial ecology and cultural and historic resources from activities beyond operational areas; impacts on threatened and endangered species; and environmental justice impacts. The NRC concluded that all of the remaining issues were generic with SMALL impacts (NRC 2002a).

Based on its review of Supplement 1 to NUREG-0586, NMC considers these generic conclusions to be appropriate for PINGP for purposes of this ER. With respect to those environmental issues identified as site-specific:

- NMC has no reason at this time to believe that PINGP decommissioning would involve land use disturbance off-site or beyond current operational areas.
- Decommissioning activities would be subject to substantial environmental reviews as noted above.
- No significant historic or archeological resources that exist on the site would be disturbed during decommissioning (Section 2.10 of this ER).
- The closest minority or low-income population to PINGP is located adjacent to PINGP, the Prairie Island Indian Community (PIIC), and is the only minority or low-income population (as defined by NRC) in the Dakota, Goodhue, and Pierce County area (Table 2.5-2 and Figure 2.5-2 of this ER).
- Only three threatened, endangered, or candidate species are known to occur at the PINGP site (Section 2.3.3 of this ER), for which the following are decommissioning impact considerations:
    - Peregrine falcons (state-threatened) successfully nest on the PINGP Unit 1 Containment Building. Removal of the containment building would eliminate one of only 25 successful nesting sites that currently exist in the State. Adverse impacts could be noticeable, but not destabilizing (i.e., MODERATE) in the absence of mitigation. However, NMC would work with the Minnesota Department of Natural Resources (MN DNR) to provide alternative nesting habitat and ensure that adverse impacts would be SMALL.

- The paddlefish (state-threatened) was once common in the Mississippi River from Lake Pepin downstream. Paddlefish are still found in these areas and are occasionally collected during fish population studies. NMC expects that termination of PINGP operations and decommissioning would not involve activities beyond current operational areas. NMC assumes there would be little or no opportunity for significant adverse impacts on this species from decommissioning.

- The Higgins eye pearlymussel (Federal and state-endangered) is a small to medium-sized freshwater mussel. It is found in rivers in areas of deep water and moderate currents. Because termination of PINGP operations and decommissioning would not involve activities beyond current operational areas, NMC assumes there would be little or no opportunity for significant adverse impacts on this species from decommissioning.

NMC notes that decommissioning activities and their impacts are not discriminators between the proposed action and the no-action alternative. License renewal would only postpone decommissioning for 20 years, and NRC has established in the GEIS that the timing of permanent cessation of plant operations does not substantially influence the environmental impact of decommissioning. NMC adopts by reference the NRC findings that the impacts of delaying decommissioning until after the license renewal terms would be SMALL (10 CFR 51).

Environmental impacts that could result more directly from terminating plant operations (e.g., from cessation of thermal effluents, reduced property tax payments, workforce reductions) are not in the scope of the analyses presented in Chapter 7 of the GEIS or in Supplement 1 to NUREG-0586, but are discussed in Section 8.4 of the GEIS and in the latter document (NRC 2002a). With the potential exception of ecological resources and socioeconomics, the NRC's generic evaluation of these issues indicates that environmental impacts of terminating operations would be SMALL (NRC 1996a). Based on its review of the discussion in these documents and information presented in this ER, NMC considers NRC's generic evaluation and conclusions in Section 8.4 of the GEIS to be appropriate for PINGP. With particular respect to ecological resources and socioeconomics impacts:

- NMC expects that termination of PINGP operations would have little, if any, adverse effect on ecological resources, considering occurrence and habitat affinities of threatened or endangered species (Section 2.3 of this ER), the small significance of current operational impacts (Chapter 4 of this ER), and the expectation that transmission lines from PINGP addressed in this ER would continue to be used (Section 3.1.4 of this ER).

- NMC notes that terminating PINGP operations would result in a decrease in tax revenues to local jurisdictions 20 years sooner than if the PINGP operating licenses are renewed. Property tax payments attributable to PINGP represent more than 30 percent of the operating budget for the City of Red Wing (Section 2.7 and

Table 2.7-1 of this ER) and, by NRC criteria, losses greater than 20 percent have destabilizing impacts on the governments involved (NRC 2002a).

In consideration of the above, NMC concludes that terminating operations and decommissioning PINGP could result in SMALL impacts on ecological resources and LARGE socioeconomic impacts from loss of tax revenues by the City of Red Wing 20 years earlier than would occur if the PINGP operating licenses were renewed. NMC further concludes that terminating operations and decommissioning PINGP would result in SMALL impacts with respect to the remaining resource areas evaluated, providing little or no basis for discriminating between the proposed action and the no-action alternative. The environmental impacts of replacement options considered in Section 7.3 of this ER provide additional information useful for evaluating the relative environmental merits of the proposed action versus the no-action alternative.

### 7.1.2 REPLACEMENT CAPACITY

PINGP is a baseload facility, providing a net baseload capacity of 1,044 MWe (NMC 2005) and in 2006 generated approximately 8.1 terawatt-hours of electricity (EIA 2006). This power, equivalent to the energy used by approximately 800,000 residential customers, would be unavailable to Xcel Energy’s customers if the PINGP operating licenses were not renewed. If the PINGP operating licenses were not renewed, Xcel Energy would need to build new baseload generating capacity, purchase power, or reduce baseload power requirements through demand reduction to ensure they meet the electric power requirements of their customers. Replacement options discussed in Section 7.2 include purchasing power, building new generating facilities, delaying retirement of non-nuclear assets, and reducing power requirements through demand reduction.

## 7.2 ALTERNATIVES THAT MEET SYSTEM GENERATING NEEDS

In Section 7.2.1, NMC provides background information pertinent to the identification and selection of alternatives available to replace PINGP baseload generation. Alternatives NMC considers to be reasonable are described in Section 7.2.2. Section 7.2.3 describes other alternatives NMC evaluated and rationale for not considering them further in this ER.

### 7.2.1 GENERAL CONSIDERATIONS

#### 7.2.1.1 Current and Projected Generating Capability and Utilization

Current and anticipated future electric power generating capability and utilization are indicative of the technical and economic viability of technologies for generating electricity, and therefore of potential alternatives to replace baseload power produced by PINGP. In 2005, electric generators in Minnesota had a total generating capacity of 12,105 MWe. This capacity includes units fueled by coal (45.0 percent), natural gas (26.1 percent), nuclear (13.4 percent), other renewables (7.9 percent), petroleum (6.1 percent), hydroelectric (1.5 percent), and other (0.1 percent). In 2005, the electric industry in Minnesota provided approximately 53.0 terawatt-hours of electricity. Actual utilization of generating capacity in Minnesota was dominated by coal (62.1 percent), followed by nuclear (24.2 percent), natural gas (5.2 percent), other renewables (5.0 percent), petroleum (1.5 percent), hydroelectric (1.5 percent), and other (0.6 percent) (EIA 2007). Figures 7.2-1 and 7.2-2 illustrate Minnesota's electric industry generating capacity and utilization, respectively.

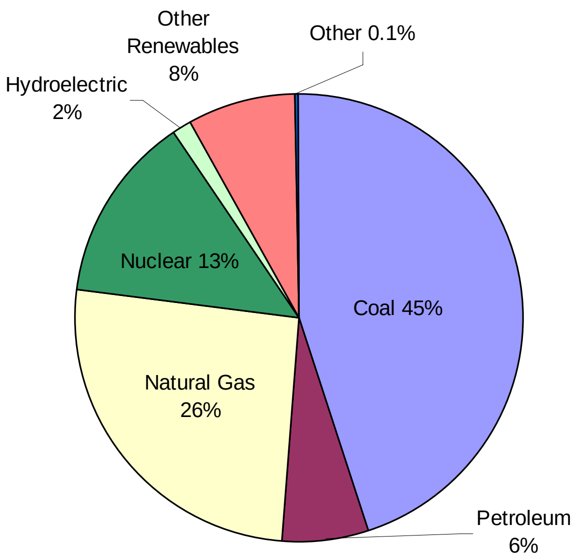


**FIGURE 7.2-1. 2005 MINNESOTA GENERATING CAPACITY BY FUEL TYPE (EIA 2007)**

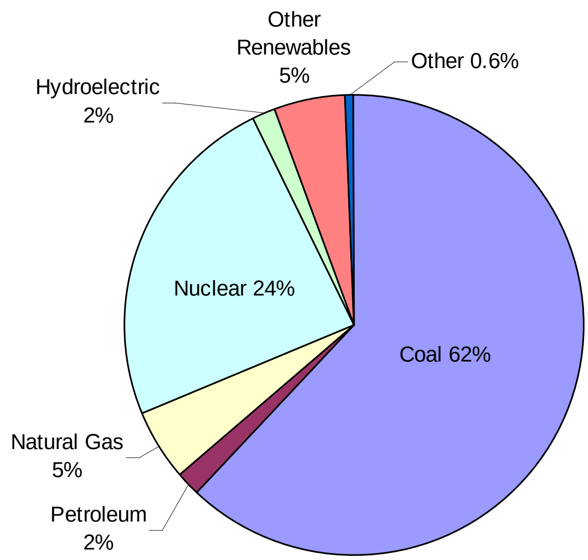


**FIGURE 7.2-2. 2005 MINNESOTA GENERATION BY FUEL TYPE (EIA 2007)**

Comparison of generating capacity with actual utilization of this capacity indicates that coal and nuclear are used by electric generators in Minnesota substantially more relative to their capacity than either petroleum-fired or gas-fired generation. This condition reflects the relatively low fuel cost and baseload suitability for nuclear power and coal-fired plants, and relatively higher use of petroleum and gas-fired units to meet peak loads. The use of petroleum and gas-fired units to meet peak loads is indicative of higher cost and greater air emissions associated with gas and petroleum firing. Capacity from renewable resources is limited and utilization can vary substantially depending on resource availability.

Insight regarding Minnesota's future generation portfolio can be gained from U.S. Department of Energy (DOE) Energy Information Agency (EIA) projections for the nation and the Mid-Continent Area Power Pool (MAPP) region, which includes Minnesota and all or part of surrounding states and two Canadian provinces (Manitoba and Saskatchewan) (MAPP 2007). Nationally, coal-fired generation is expected to remain the predominant source of electricity through 2025 and the relative amount of generation from natural gas and coal is expected to increase. Aggregate generation from nuclear plants is expected to remain near present levels with no new facilities expected in the MAPP region. Generation from renewable sources is expected to exhibit relatively slow growth because of the relatively low costs of fossil-fired generation and because competitive electricity markets favor less capital-intensive technologies (EIA 2004a, EIA 2004b).

Projected increases in capacity and generation in the MAPP region for the 2004-2010 and 2004-2025 periods (EIA 2004b) are illustrated by the following selective summary tabulation:

| MAPP Projected Capacity Increase | | | | | MAPP Projected Generation Increase | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2004-2010 | | 2004-2025 | | | 2004-2010 | | 2004-2025 | |
| **Source** | **MW** | **%** | **MW** | **%** | **Source** | **GWh** | **%** | **GWh** | **%** |
| Coal Steam | - 40 | - 1 | 5,240 | 45 | Coal | 14,380 | 78 | 53,300 | 85 |
| Nuclear | 0 | 0 | 0 | 0 | Nuclear | 110 | 1 | 110 | < 1 |
| Combined Cycle | 210 | 7 | 620 | 5 | Natural Gas | 890 | 5 | 5,140 | 8 |
| Combustion Turbine/Diesel | 1,750 | 62 | 4,730 | 41 | Petroleum | - 30 | < 1 | 860 | 1 |
| Renewables | 810 | 29 | 950 | 8 | Renewables | 2,970 | 16 | 3,530 | 5 |
| All Sources | 2,810 | | 11,610 | | All Sources | 18.320 | | 62,940 | |

As indicated by this data summary, EIA projects there will be no appreciable change in nuclear capacity or generation the MAPP region. No coal-fired capacity additions are projected in the MAPP region in the 2004-2010 period, but in 2004-2025 most capacity addition is from coal-fired units; by far the greatest increase in generation during both periods is expected to be from coal. Combustion turbine/diesel and combined cycle together represent significant projected capacity additions in both periods, but the increase is predominantly peaking capacity because most is from combustion turbine/diesel units (likely to be nearly all combustion turbines), and the contribution to projected generation from natural gas and petroleum, typical combustion turbine fuels, is low.

EIA projects a greater relative increase in capacity and generation from renewables in MAPP than is projected nationally through 2025. This is particularly true in the 2004-2010 period, when its contribution to generation increases is expected to exceed that of natural gas. This phenomenon is mostly the result of ongoing and projected development of regional wind-conversion facilities, which are projected to account for approximately 90 percent or more of renewable capacity and generation in the 2004-2010 and 2004-2025 periods (EIA 2004b). Minnesota has the potential to develop wind energy resources, particularly in the Buffalo Ridge area in the southwestern part of the state (MDC 2006).

The MAPP regional information above does not include predictions based on legislation recently signed by the Governor of Minnesota. The Next Generation Energy Act of 2007 establishes statewide greenhouse gas emissions reduction goals of 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050. Additional legislation signed earlier in the year also requires Minnesota’s electric utilities to provide 25 percent of the electricity generated to be from renewable sources by 2025 (Office of the Governor 2007). This required reduction in greenhouse gas emissions and increased generation requirements from renewable sources may preclude the development of additional coal-fired capacity as described above and replace that generating capacity with renewable sources.

#### 7.2.1.2 Effects of Electric Power Industry Restructuring

The U.S. electric power industry began its transition from a regulated monopoly structure to a competitive retail market with the passage of the Federal Energy Policy Act of 1992 and associated state initiatives. As summarized by the EIA, the Federal Energy Regulatory Commission (FERC) Order 888 requires that all public utilities provide open access to their transmission lines, and functionally separate their wholesale power services and transmission services, and encourage the creation of independent system operators to ensure independence in transmission operations (EIA 2005). Order 889 prevents public utility power marketing organizations from having preferential access to transmission information, and requires that such information be equally shared with transmission customers. FERC Order 2000 encouraged all transmission owners to voluntarily allow operation of their transmission assets by independent Regional Transmission Operators to improve market performance and equal access (FERC 2002).

In the wake of these federal initiatives and upon approval of the Minnesota Public Utilities Commission (MPUC), Minnesota’s investor-owned utilities, including Xcel Energy, have joined the Midwest Independent System Operators (MISO), and have transferred functional control (but not ownership) of their transmission facilities to MISO, the operations of which are subject to FERC approval (MDC 2004).

Sixteen states and the District of Columbia have fully implemented their legislation and commission orders and currently allow full retail access for all customers. However, no state has passed restructuring legislation since June of 2000, when the California and western power crisis was just beginning. Six states that passed restructuring legislation later delayed, repealed, or indefinitely postponed implementation. A total of 34 states have repealed, delayed, suspended, or limited retail access or are no longer considering retail access (VSCC 2006).

Minnesota has not enacted major restructuring initiatives. Rather, Minnesota and most states in MAPP region have retained the traditional regulatory model in which electric utilities are comprehensively regulated to ensure reliable electric service within pre-determined utility service territories (MDC 2004). In this context, Xcel Energy, through a regulated operating subsidiary (NSP), provides a comprehensive portfolio of energy related products and services in Minnesota, including generation, purchase, transmission, distribution, and sale of electricity; purchase, distribution and sale of natural gas to retail customers; and transport of customer-owned natural gas (Xcel Energy 2006a). Xcel Energy's service area in Minnesota is located predominantly in the southern part of the state from St. Cloud southward, including the Minneapolis-St. Paul Metropolitan area (Xcel Energy 2006b). Its Minnesota power generating facilities are also located in the southern part of the state (Xcel Energy 2006c).

Results of the utility restructuring initiatives discussed above are reflected in increases in the non-utility share of new electric generating capacity and generation. These increases are lower than national averages in Minnesota, which retains a traditional regulatory structure. Nonetheless, non-utility share of capacity in the state increased from 6.2 percent during 1990 to 12.9 percent in 2005. The non-utility share of generation increased from 3.5 percent to 11.7 percent in this same period (EIA 2007).

In the regulatory environment described above, and as specifically provided by Minnesota statute (Minnesota Statute 216B.37, 216B.04), Xcel is obligated to ensure the electric power needs of customers in its service area are met and to take appropriate action (e.g., power purchase, development of new generation capacity) to accommodate any shortfall in available power resulting from a decision by NRC to not renew the PINGP operating license. These actions would be undertaken in the context of planning and permitting requirements and activities of the MPUC, Minnesota Environmental Quality Board (MEQB), and various other state agencies, including the following:

- Integrated Resource Plan - Regulated utilities submit to the MPUC for approval biennial integrated resource plans projecting future resource needs and providing analysis and proposals to reduce and manage energy demand and develop new generating facilities (MDC 2006).

- Transmission Plan - Transmission-owning utilities in the state collaboratively identify inadequacies in the state's transmission system and propose solutions biennially (MDC 2006).

- Certificate of Need (CON) - Development in Minnesota of electric power generating plants having a capacity of 50 MW or more, high voltage transmission lines with a capacity of 200 kilovolts (kV) or more, and major natural gas pipelines (i.e., those having an operating pressure over 200 pounds per square inch (psi) and instate length of more than 50 miles) requires MPUC approval either by issuance of a CON or other means (e.g., integrated resource plan approval). The CON process includes an initial review of the project with respect to environmental impacts and alternatives, including conservation and renewable alternatives (MDC 2006).

- Site/Route Permit - Development in Minnesota of electric power generating equipment with a capacity of 50 MW or more, large wind energy conversion systems (combination of wind turbines with a capacity of 5 MW or more) and, regardless of length, transmission lines operating at 100 kV or more and natural gas pipelines more than 6 inches in diameter operating at pressures more than 275 psi are required to obtain a site or route permit from MEQB. This process entails detailed environmental review, analysis of alternatives, and opportunity for public input (MDC 2006).

- Other Environmental Approvals - A variety of additional permits and approvals from other federal, state, and local entities also may be required to develop electrical energy facilities in Minnesota.

#### 7.2.1.3 Mixture of Generating Sources

NRC indicated in the GEIS that, while many methods are available for generating electricity and a huge number of combinations or mixes can be assimilated to meet system needs, such expansive consideration would be too unwieldy given the purposes on the alternative analysis. Therefore, NRC determined that a reasonable set of alternatives should be limited to analysis of single discrete electrical generation sources and only those electric generation technologies that are technically reasonable and commercially viable (NRC 1996a). Consistent with the NRC determination, NMC has not evaluated mixes of generating sources. However, the impacts from coal- and gas-fired generation presented in this chapter would bound the impacts from any combination of the two technologies.

### 7.2.2 REASONABLE ALTERNATIVES

In view of the background information presented in Section 7.2.1 and additional information presented in this section, NMC considers that purchased power and development of new generating capacity represented by modern natural gas combined-cycle and pulverized coal-fired steam power generation technologies are reasonable alternatives to replace PINGP baseload generating capacity in the event its operating licenses are not renewed. NMC describes these alternatives in the following subsections as reasonable hypothetical scenarios for analysis without regard to whether they would be developed by Xcel Energy or others.

The following sections present purchased power (Section 7.2.2.1), gas-fired generation (Section 7.2.2.2) and coal-fired generation (Section 7.2.2.3) as reasonable alternatives to license renewal. Section 7.2.3 discusses reduced demand and presents the basis for concluding that it is not a reasonable alternative to license renewal. Section 7.2.3 also discusses other alternatives that NMC has determined are not reasonable and the bases for these determinations.

NMC analyzed locating hypothetical new coal- and gas-fired units at the existing PINGP site and at an undetermined green field site. NMC concluded that sufficient room would not be available at the PINGP site for new construction. Locating hypothetical units at a greenfield site has, therefore, been applied to the representative coal- and gas-fired units.

For comparability, NMC selected gas- and coal-fired units of equal electric power capacity. One unit with a net capacity of 1,044 MWe could be assumed to replace the 1,044-MWe PINGP net capacity. However, industry experience indicates that, although custom size units can be built, using standardized sizes is more economical. For example, standard-sized units include a gas-fired combined-cycle plant of 520 MWe net capacity (Chase and Kehoe 2000). Two of these standard-sized units would have 1,040 MWe net capacity. For comparability, NMC set the net power of the coal-fired unit equal to the gas-fired plant (1,040 MWe). Although this provides slightly less capacity than the existing units, it ensures against overestimating environmental impacts from the alternatives.

It must be emphasized, however, that these are hypothetical scenarios. Xcel Energy does not have plans for such construction.

#### 7.2.2.1 Purchased Power

Most Minnesota utilities rely on electricity generated outside of Minnesota to meet their customer’s needs, and in some manner all of them, including Xcel Energy, use the regional grid to import power at various times. However, many major transmission lines into and out of Minnesota are nearing operational limits, which could affect reliability in the future and impede the ability to import power if additional transmission infrastructure is not developed. These problems are recognized by state and regional transmission planning organizations and mechanisms are in place to identify and address transmission constraints affecting system reliability (MDC 2004). Therefore, NMC assumes purchased power would be a reasonable alternative to replace power lost in the event the PINGP operating licenses are not renewed, but could involve additional environmental impacts resulting from the need to increase transmission capability into the state.

Technologies that would be used to generate the purchased power are a matter of conjecture but, based on the discussion of Minnesota capacity and utilization data and national and region projections, NMC considers that the most likely candidates would be coal-fired and nuclear sources during off-peak periods and gas-fired sources during on-peak periods, probably supplemented by power from renewable sources, particularly wind-conversion facilities. Because of the size of the block of baseload capacity supplied by PINGP, construction of additional baseload generating capacity using one or more of these technologies would likely be required even under the power purchase scenario. Such construction could occur within or outside of Minnesota. Therefore, a power purchase alternative would likely not eliminate the need to construct replacement baseload capacity, but rather shift it to another region. Accordingly, the impacts of power purchase alternative would be expected to be similar to the impacts of baseload alternatives analyzed in Section 7.3.2 and 7.3.3 of this ER.

In view of constraints in the existing transmission infrastructure, Xcel Energy expects that substantial additions to either the 500-kV or 345-kV transmission systems in the Upper Midwest would be required to import power into Minnesota in amounts that would replace generation from PINGP. Specific plans for such additional transmission would entail detailed studies beyond the scope or purpose of this ER. However, for purposes of analysis, NMC assumes that 100 miles of new 345-kV transmission line(s) using a 150-foot wide right-of-way (ROW) would be needed in the Upper Midwest, assumed for analysis to be located in southern Minnesota south of the Twin Cities metropolitan area, the state’s main load center, in an area roughly bounded by existing 345-kV lines entering the state from the south.

The location and design of the transmission line would be subject to substantial environmental restrictions and review, including site permit review and opportunity for public participation. Therefore, NMC assumes it would be sited, developed, and operated in accordance with all applicable environmental requirements and in a manner that ensures adverse environmental impacts would not be destabilizing with respect to resources of concern.

#### 7.2.2.2 Gas-Fired Generation

For purposes of this analysis, NMC assumed development of a modern natural gas-fired combined-cycle plant with design characteristics similar to those being planned or developed elsewhere in Minnesota could be configured to replace power currently generated by PINGP. The Mankato Power Plant, developed by Calpine Corporation to generate baseload power for Xcel Energy near the city of Mankato, approximately 50 miles southwest of the Twin Cities, Minnesota, meets these general criteria. NMC used selected plant characteristics as described in the environmental assessment for that facility (MEQB 2004) as a main source of information for the representative plant characteristics. NMC assumes that the representative plant would be located at a greenfield site. Table 7.2-1 presents the basic gas-fired alternative characteristics.

The assumed representative plant consists of two combined cycle units each consisting of steam combustion turbines (CTs) with an associated heat recovery steam generator (HRSG) that supply steam to a steam turbine generator. Net generating capacity of each combined cycle unit is approximately 520 MW, for a total of 1,040 MW for the representative plant. Although capacity of the representative plant is slightly less than that of PINGP (1,044 MW), it is nonetheless reasonably comparable for purposes of this ER.

NMC assumes for conservatism that the representative plant would use natural gas as its only fuel. However, the facility could reasonably be constructed with the capability to fire oil as backup fuel for use during high demand or higher cost periods for natural gas, thus improving fuel supply capabilities and operating cost. Based on the information presented in Table 7.2-1, total annual heat input from natural gas would be approximately 48,700,000 million British thermal units, corresponding to an annual natural gas consumption of approximately 48.3 billion cubic feet.[1]

Availability of sufficient capacity from existing natural gas transmission infrastructure in Minnesota to supply the plant in 2013 is conjectural. NMC notes that only a limited number of natural gas generation facilities can be added to the existing system without significant upgrades (MDC 2006). However, the Minnesota Department of Commerce (MDC) indicates that, while existing infrastructure is near capacity, there is a potential for more natural gas supplies becoming available within the state as long as liquefied natural gas displaces natural gas supplies consumed in other parts of the country, and there appears to be adequate supplies available to meet projected demand for some time beyond 2025 (MDC 2006). In view of these considerations, NMC expects that the representative plant would likely contribute to the need for major gas supply infrastructure in the state, but assumes that no such major improvements would be needed.

NMC estimates that the representative plant with associated support facilities would occupy approximately 41 acres (TtNUS 2007a). Additional land could be needed as buffer from adjacent land uses. For example, the NRC estimates that 110 acres would be required for a 1,000 MW plant (NRC 1996a). NMC assumes that the representative plant would be located at a greenfield site. Offsite infrastructure needed for the representative plant could reasonably include a natural gas supply pipeline, transmission line, and a rail spur.

NMC assumes for this assessment that construction of the gas-fired plant would be timed to enable its operation in 2013 when the first PINGP operating license expires. NMC estimates that the plant would be constructed in approximately 3 years with a peak onsite workforce of approximately 629 workers, and that a permanent full-time workforce of approximately 35 persons would operate the plant (TtNUS 2007a).

### 7.2.2.3 Coal-Fired Generation

NRC has routinely evaluated coal-fired generation alternatives for nuclear plant license renewal. In the GEIS Supplement for McGuire Nuclear Station (NRC 2002b), NRC analyzed 2,400 MWe of coal-fired generation capacity. NMC has reviewed the NRC analysis, considers it to be sound, and notes that it analyzed more generating capacity than the 1,040 MWe discussed in this analysis. In defining the PINGP coal-fired

1 Annual Natural Gas Requirement (Btu) = [Natural Gas Heat Input] x [Heating Value of Fuel] = [Total Gross Capability (542 MW) x Number of Units (2) x Heat Rate (6,040 Btu/kW-hour) x 1,000 kW/MW x Capacity Factor (0.85) x 8,760 hr/yr]. Therefore: Natural Gas Heat Input = $4.872 \times 10^{13}$ Btu/yr, or $4.872 \times 10^{7}$ MMBtu/yr. Volume of gas required per year = Annual Natural Gas Requirement (Btu/yr) x [Heating Value of Fuel (1 scf/1,008 Btu)] = $4.833 \times 10^{10}$ scf/yr, or 48.3 billion scf/yr. Table 7.2-1 lists all necessary parameters and values.

alternative, NMC has used site- and Minnesota-specific input and has applied the NRC analysis, where appropriate.

Specific coal generating technologies that would represent viable alternatives in 2013 and 2014 when the PINGP operating licenses expire are less certain than for a natural gas-fired plant, particularly in view of potentially higher air emissions compared to natural gas firing. NMC notes that integrated gasification combined-cycle (IGCC) technology could be viable based on potential development of the Mesaba Energy Project. The Mesaba Energy Project is an IGCC facility with a capacity of approximately 600 MW proposed for development in northern Minnesota (MDC 2004). However, the Mesaba facility would be the largest capacity IGCC facility constructed to date in the U.S and represents technology that is not yet fully demonstrated commercially at the size proposed. IGCC demonstration plants to date have been much smaller (MDC 2004). Given these circumstances, the long-term reliability of IGCC may not be known at the point a decision needs to be made regarding replacement of PINGP capacity. Xcel Energy recognizes modern pulverized coal-fired steam units with advanced, clean-coal technology air emission controls as currently proven technology that is economically competitive and commercially available in large-capacity unit sizes that could effectively replace PINGP. In the future, an IGCC with carbon sequestration technology might achieve lower emissions, but effective carbon sequestration technology currently does not exist. Therefore, NMC uses a representative plant of this type for purposes of impact evaluation, noting that air emissions impacts of IGCC may be lower than modern pulverized coal, but likely would be comparable to or higher than the gas-fired combined-cycle alternative (DOE 1999).

The representative plant consists of two commercially available standard-sized units having a nominal net output of approximately 520 MW each, for a total of 1,040 MW, comparable to PINGP's net capacity of 1,044 MW. Table 7.2-2 presents the basic coal-fired alternative emission control characteristics. NMC based its emission control technology and percent control assumptions on alternatives that the U.S. Environmental Protection Agency (EPA) has identified as being available for minimizing emissions (EPA 1998a). NMC assumes that the representative plant would be located at a greenfield site.

Table 7.2-2 lists basic specifications for the plant. Based on this information, annual coal consumption for the facility would be approximately 4.7 million tons[2]. The representative plant would be designed to meet applicable standards with respect to control of air and wastewater emissions. NMC estimates that approximately 64,700 tons of limestone could be needed annually to operate the scrubber assumed for control of sulfur oxides ($SO_x$) emissions.

NMC estimates that approximately 170 acres would be required to accommodate the generating plant and related onsite ancillary and support facilities and infrastructure

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2 Coal Combusted (tons/year) = Gross Capability (553 MW) x Number of Units (2) x Heat Rate (10,200 Btu/kilowatt-hour) x 1,000 kilowatt/MW x 1/Fuel Heat Value (8,914 Btu/lb) x 0.0005 (ton/lb) x Capacity Factor (0.85) x 8,760 hr/year = 4.7 million tons/yr. All necessary parameters and values are provided in Table 7.2-1.

(e.g., coal and limestone transport, storage, and handling facilities; switchyard and onsite transmission lines; storage tanks; cooling towers; technical and administration buildings; access roads; parking) (TtNUS 2007a). The extent to which these solid wastes could be used beneficially is dependent on such factors as air emission control design specifics and future demand. However, approximately 30 percent of the ash from Xcel Energy coal-fired generating plants goes to such beneficial uses as concrete products and roadbed material (Xcel Energy 2004a). Therefore, NMC assumes for purposes of this ER that 30 percent of the ash from the representative coal-fired plant would be beneficially used, and that the remainder of this air emission control waste would be landfilled onsite. Assuming an average fill depth of 30 feet, approximately 180 acres would be required over an assumed 40-year plant life (TtNUS 2007b). Therefore, the minimum total land requirement for the plant is assumed to be approximately 350 acres. Additional land likely would be necessary to allow for a peripheral buffer. For example, the NRC estimates that a total of 1,700 acres could be required for a larger (1,000 MW) plant (NRC 1996a).

NMC assumes that construction of the coal-fired unit would be timed to enable its operation when the first PINGP operating license expires in 2013, and estimates that the plant could be constructed in approximately 5 years with peak onsite workforce of approximately 1,700 workers. Depending on the level of automation, a permanent work force of 120 full-time employees would likely be required to operate the plant (TtNUS 2007a).

### 7.2.2.4 Siting Considerations

Xcel Energy considers it unlikely that either of the representative plants would be developed at the PINGP site because sufficient room would not be available to site the new construction. Therefore, NMC assumes for purposes of this ER that the hypothetical alternative would be located at a greenfield site in southern Minnesota generally south of the Twin Cities. The choice of a specific location for the plant would require detailed studies and analysis beyond the scope or necessity for this ER. However, NMC notes that Northern States Power (NSP) has recently considered areas generally south of the Twin Cities (e.g., at Mankato and in the Rosemount area, near the Mississippi River immediately southeast of the Twin Cities metropolitan area), as potentially favorable for siting natural gas-fired or coal-fired power plants for new generation.

NMC has made the following assumptions to reasonably define offsite infrastructure that would be needed to locate either plant at a greenfield site. NMC assumes that 5 miles of new natural gas supply pipeline would be needed to supply the gas-fired plant and 10 miles of new rail would be required for delivery of coal and limestone to the coal-fired plant. In addition, NMC assumes 5 miles of new 345-kV transmission line would be needed to connect to the grid. NMC assumes that the supply pipeline would require a 30-foot wide ROW, a rail spur would require a 50-foot wide ROW, and the transmission line would occupy a 150-foot wide ROW.

As indicated by discussion elsewhere in this ER, the location and design of either alternative plant and associated offsite infrastructure would be subject to substantial environmental restrictions and review, including MEQB site permit review and opportunity for public participation. Therefore, NMC assumes the representative plant and associated offsite infrastructure would be sited, developed, and operated in accordance with all applicable environmental requirements and in a manner that ensures adverse environmental impacts would not be destabilizing with respect to resources of concern.

### 7.2.3 OTHER ALTERNATIVES

This section identifies alternatives that NMC has determined are not reasonable and the NMC bases for these determinations. NMC accounted for the fact that PINGP is a base-load generator and that any feasible alternative to PINGP would also need to be able to generate base-load power. In addition to coal-fired and natural gas-fired generation, the NRC evaluated several other generation technologies in the GEIS (NRC 1996a). NMC has considered these options as potential alternatives to continued operation of PINGP and determined them to be unreasonable on the basis of economics, high land-use impacts, low capacity factors, geographic limitations, insufficiently developed technology, or other significant reasons.

#### 7.2.3.1 Demand Side Management

Under provisions of Minnesota Statute 216B.241, Minnesota public utilities, rural electric cooperatives, and municipal utilities are required to invest 1.5 percent of in-state revenues in projects designed to reduce their customers' consumption of electricity and improve efficient use of energy resources. Utilities that operate nuclear generating facilities like PINGP are required to invest 2.0 percent of revenues in this manner. Cost of this program, which is administered by the MDC, is recovered from utility customers (MDC 2006). Each utility is required to submit to the MDC for approval an annual conservation improvement plan (CIP) which details its energy-saving programs (MDC 2006). Within certain limits as specified under Minnesota Statute 216B.241, the MDC may specifically direct utilities like Xcel Energy in regards to investments and expenditures to be made for energy conservation.

In this context, Xcel Energy has in place a wide variety of electrical energy conservation (i.e., demand-side management, or DSM) programs and activities, including:

- Conservation Programs – programs like Xcel Energy's Energy Solutions newsletter and internet-based information resources designed to educate and inform customers about energy efficiency and Xcel Energy offerings.

- Energy Efficiency Programs – programs like ConservationWise from Xcel Energy$^{SM}$ that help customers increase energy efficiency by providing rebates, pricing, or other incentives to purchase energy efficient systems or components (e.g., boilers, air conditioning systems, lighting, motors); renovate facilities that meet specific energy efficiency standards (e.g., roofing); undertake energy conservations assessments; and obtain expert energy conservation design assistance.

- Load Management Programs – programs such as OperationWise from Xcel Energy$^{SM}$ that encourage customers to switch load to customer-owned standby generators during periods of peak demand, and include features like Saver's Switch® that encourage customers to allow a portion of their load to be interrupted during periods of peak demand.

Details of Xcel Energy DSM programs are provided in its most recent CIP.

In Xcel Energy's 2004 Integrated Resource Plan, Xcel Energy established the DSM goals for the 2005-2019 planning period. This plan established aggressive targets of 3,773 gigawatt-hours (GWh) of cumulative energy savings and 1,063 MW of cumulative peak demand savings in Xcel Energy's service area over this period (Xcel Energy 2004b).

Recent legislation, the Next Generation Energy Act of 2007, signed in May of 2007 by the Governor of Minnesota, introduces reforms to the existing DSM programs in Minnesota (Office of the Governor 2007). This legislation includes a provision for utilities to reduce electricity demand by 1.5 percent per year. It also transitions the CIP program from a spending program to an energy savings program. These reforms are expected to double the amount of electricity saved (MDC 2007).

NMC notes that even if these aggressive annual DSM savings targets required by the CIP and the Next Generation Energy Act of 2007 were achieved, the cumulative savings through 2013 would be insufficient to replace generation lost as a result of PINGP operations termination at the end of its current operating licenses. Moreover, Xcel Energy credits these DSM goals from the CIP in its demand forecasts, which indicate the need for substantial amounts of energy to meet obligations in its service area even assuming the PINGP operating license is renewed. In addition, DSM tends to reduce peak demand, and has less effect on reducing demand for baseload capacity. Therefore, NMC concludes that DSM does not represent a meaningful alternative to renewal of the PINGP operating license.

#### 7.2.3.2 Wind

Wind power, by itself, is not suitable for large base-load generation. As discussed in Section 8.3.1 of the GEIS, wind has a high degree of intermittence, and average annual capacity factors for wind plants are relatively low (less than 30 percent). Wind power, in conjunction with energy storage mechanisms, might serve as a means of providing base-load power. However, current energy storage technologies are too expensive for wind power to serve as a large base-load generator.

Based on American Wind Energy Association (AWEA) estimates from 2005, Minnesota has the technical potential (the upper limit of renewable electricity production and capacity that could be brought online, without regard to cost, market acceptability, or market constraints) for roughly 75,000 MWe of installed wind power capacity. The full exploitation of wind energy is constrained by a variety of factors including land availability and land-use patterns, surface topography, infrastructure constraints, environmental constraints, wind turbine capacity factor, wind turbine availability, and grid availability. When these constraints on wind energy development are considered, the achievable wind energy potential is expected to fall in the range of 20-40 percent of technical potential estimates or 15,000 - 30,000 MWe. As of the end of 2005 a total of 744 MWe of wind energy had been developed in Minnesota (AWEA 2006).

Wind farms, the most economical wind option, generally consist of 10-50 turbines in the 1-3 MWe range. Estimates based on existing installations indicate that a utility-scale wind farm would occupy about 50 acres per MWe of installed capacity (McGowan & Connors 2000). Wind farm facilities would occupy 3 to 5 percent of the wind farm’s total acreage (McGowan and Connors 2000). Therefore, replacement of PINGP generating capacity with wind power, even assuming ideal wind conditions, would require about 149,000 acres (230 square miles) of which about 4,500 acres (7 square miles) would be occupied by turbines and support facilities. Based on the amount of land needed to replace PINGP, the wind alternative would require a large green field site, which would result in a large environmental impact. Additionally, wind plants have aesthetic impacts, generate noise, and can harm flying birds and bats.

The scale of this technology is too small to directly replace a power plant of the size of PINGP, capacity factors are low (30 to 40 percent), and the land requirement (7 square miles) is large. The expected increase in wind energy generation will likely meet the additional renewable generation required by the Next Generation Energy Act of 2007 and not be available to replace base-load generation. Therefore, NMC has concluded that wind power is not a reasonable alternative to PINGP license renewal.

#### 7.2.3.3 Solar

By its nature, solar power is intermittent. In conjunction with energy storage mechanisms, solar power might serve as a means of providing base-load power. However, current energy storage technologies are too expensive to permit solar power to serve as a large base-load generator. Even without storage capacity, solar power technologies (photovoltaic and thermal) cannot currently compete with conventional fossil-fueled technologies in grid-connected applications, due to high costs per kilowatt of capacity (NRC 1996a). However, Xcel Energy’s portfolio includes purchased power of 8 megawatts of solar.

The amount of solar radiation that Minnesota receives ranges from 4.0 kilowatt hours per square meter per day in the northeast part of the state to nearly 5.0 kilowatt hours per square meter per day in the southwest corner (NREL 2006). Estimates based on existing installations indicate that utility-scale plants would occupy about 7.4 acres per MWe for photovoltaic and 4.9 acres per MWe for solar thermal systems (DOE 2004). Utility-scale solar plants have only been used in regions, such as southern California, that receive high concentrations (5 to 7.2 kilowatt hours per square meter per day) of solar radiation. NMC believes that a utility-scale solar plant located in Minnesota, which receives 4.0 to 5.0 kilowatt hours of solar radiation per square meter per day, would occupy about 10.62 acres per MWe for photovoltaic and 7.03 acres per MWe for solar thermal systems. Therefore, replacement of PINGP generating capacity with solar power would require dedication of about 16,000 acres (26 square miles) for photovoltaic and 26,000 acres (41 square miles) for solar thermal systems. The existing PINGP site is approximately 578 acres. Neither type of solar electric system would fit at the PINGP site, and both would have large environmental impacts at a greenfield site.

NMC has concluded that due to the high cost, limited availability of sufficient incident solar radiation, and amount of land needed (approximately 26 to 41 square miles), solar power is not a reasonable alternative to PINGP license renewal.

#### 7.2.3.4 Hydropower

According to the U.S. Hydropower Resource Assessment for Minnesota (Francfort 1996), there are no sites in Minnesota that would be environmentally suitable for a large hydroelectric facility. As the GEIS points out in Section 8.3.4, hydropower's proportion of United States generating capacity is expected to decline because 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.

The GEIS estimates land use of 1,600 square miles per 1,000 MWe for hydroelectric power. Based on this estimate, replacement of PINGP generating capacity would require flooding approximately 1,700 square miles, resulting in a large impact on land use. Further, operation of a hydroelectric facility would alter aquatic habitats above and below the dam, which would impact existing aquatic communities.

NMC has concluded that due to the lack of suitable sites in Minnesota for a large hydroelectric facility and the amount of land needed (approximately 1,700 square miles) hydropower is not a reasonable alternative to PINGP license renewal.

#### 7.2.3.5 Geothermal

As illustrated by Figure 8.4 in the GEIS (NRC 1996a), geothermal plants might be located in the western continental United States, Alaska, and Hawaii, where hydrothermal reservoirs are prevalent. However, because there are no high-temperature geothermal sites in Minnesota, NMC concludes that geothermal is not a reasonable alternative to PINGP license renewal.

#### 7.2.3.6 Wood Energy

As discussed in the GEIS (NRC 1996a), 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. According to the U.S.

Department of Energy, Minnesota does not have enough wood resources to replace the generating capacity of PINGP (Walsh et al. 2000).

Further, as discussed in Section 8.3.6 of the GEIS (NRC 1996a), 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 a smaller scale. 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 base-load applications. It is also difficult to handle and has high transportation costs.

NMC has concluded that, due to inadequate resources, the lack of an environmental advantage, low heat content, handling difficulties, and high transportation costs, wood energy is not a reasonable alternative to PINGP license renewal.

#### 7.2.3.7 Municipal Solid Waste

As discussed in Section 8.3.7 of the GEIS (NRC 1996a), the initial capital costs for municipal solid waste plants are greater than for comparable steam turbine technology at wood-waste facilities. This is due to the need for specialized waste separation and handling equipment.

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). Some of these impacts would be moderate, but still larger than the environmental effects of PINGP license renewal.

NMC has concluded that, due to the high costs and lack of environmental advantages, burning municipal solid waste to generate electricity is not a reasonable alternative to PINGP license renewal.

#### 7.2.3.8 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 (ethanol is primarily used as a gasoline additive), and gasifying energy crops (including wood waste). As discussed in the GEIS, none of these technologies has progressed to the point of being competitive on a large scale or of being reliable enough to replace a base-load plant such as PINGP.

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 the energy crops.

NMC has concluded that, due to the high costs and lack of environmental advantage, burning other biomass-derived fuels is not a reasonable alternative to PINGP license renewal.

#### 7.2.3.9 Petroleum

Minnesota has several petroleum(oil)-fired power plants; and from 1990 to 2005 the percentage share of power produced by oil-fired generating plants decreased from 9.0 percent to about 5.9 percent (EIA 2007). However, oil-fired generation represents a small portion of the overall generation mix in Minnesota and is more expensive than nuclear or coal-fired generation. Future increases in petroleum prices are expected to make oil-fired generation increasingly more expensive than coal-fired generation. Also, construction and operation of an oil-fired plant would have environmental impacts. For example, Section 8.3.11 of the GEIS (NRC 1996a) estimates that construction of a 1,000-MWe oil-fired plant would require about 120 acres. Additionally, operation of oil-fired plants would have environmental impacts (including impacts on the aquatic environment and air) that would be similar to those from a coal-fired plant.

NMC has concluded that, due to the high costs and lack of obvious environmental advantage, oil-fired generation is not a reasonable alternative to PINGP license renewal.

#### 7.2.3.10 Fuel Cells

Fuel cell power plants are in the initial stages of commercialization. While more than 700 large stationary fuel cell systems have been built and operated worldwide, the global stationary fuel cell electricity generating capacity in 2004 was only 132 MWe. In addition, the largest stationary fuel cell power plant is only 11 MWe (Fuel Cell Today 2003 and 2005). Recent estimates suggest that a company would have to produce about 100 MWe of fuel cell stacks annually to achieve a price of $1,000 to $1,500 per kilowatt (Kenergy Corporation 2000). However, the production capability of the largest stationery fuel cell manufacturer is 50 MWe per year (CSFCC 2002). NMC believes this technology has not matured sufficiently to support production for a facility the size of PINGP. NMC has concluded that, due to cost and production limitations, fuel cell technology is not a reasonable alternative to PINGP license renewal.

### 7.2.3.11 Advanced Nuclear Reactor

Increased interest in the development of advanced nuclear power plants has been expressed recently by members of both industry and government. However, it is extremely unlikely that a replacement for the PINGP could be planned, licensed, constructed, and on line by the time the operating licenses expire in 2013 and 2014. Further, there is currently a moratorium in Minnesota on the construction of new nuclear plants. In addition, a new nuclear plant would have environmental impacts similar to those for PINGP but would also incur the new construction impacts. Therefore, constructing a new nuclear plant would not be expected to be environmentally superior to the continued operation of PINGP.

### 7.2.3.12 Delayed Retirement of Existing Non-nuclear Units

As the NRC noted in the GEIS (NRC 1996a), 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. However, delaying retirement in order to compensate for PINGP generally would be unreasonable without major construction to upgrade or replace plant components. Xcel Energy undertakes upgrades of its older baseload plants in cases where it is reasonable to do so. Such actions are currently accounted for in Xcel Energy’s plans to meet anticipated demands irrespective of the loss of generating capacity if the PINGP operating license is not renewed and, therefore, do not represent a realistic option. In addition, NMC expects that the environmental impacts of implementing such upgrades and operating the upgraded plants are reasonably bounded by assessments presented in this chapter for the gas-fired and coal-fired alternatives.

## 7.3 ENVIRONMENTAL IMPACTS OF ALTERNATIVES

NMC evaluations of environmental impacts for the feasible replacement power alternatives are presented in the following sections. Section 7.3.1 provides NMC's impact assessment of the purchased power alternative. Sections 7.3.2 and 7.3.3 address impacts associated with the natural gas-fired and coal-fired plant alternative, respectively. Chapter 8 presents a summary comparison of the environmental impacts of license renewal and the alternatives discussed in this section.

The evaluations presented below focus on the impacts specific to these alternatives. Impacts associated with terminating operations and decommissioning PINGP (i.e., base case, Section 7.1.1 of this ER) are expected to be of SMALL significance for all resource areas addressed except socioeconomics; therefore, these generally are not further discussed. However, conclusions expressed below regarding the significance of impact for each alternative denote the total expected impact for each resource area, inclusive of the base case. The influence of the base case on these conclusions is noted where appropriate.

The new generating plants addressed in Sections 7.3.2 and 7.3.3 would not be constructed only to operate for the period of extended operation of PINGP. Therefore, NMC assumes for this analysis a typical design life of 30 years for the combined-cycle natural gas-fired plant and 40 years for the coal-fired plant, and considers impacts associated with operation for the entire design life of the units in this analysis. As discussed in Section 7.2, NMC assumes that construction of these plants would be phased to provide replacement capacity in 2013 and 2014 when respective PINGP operating licenses expire.

### 7.3.1 PURCHASED POWER

Because it would be replacing PINGP's baseload capacity, NMC assumes that the generating technology used under the power purchase alternative would likely be coal-fired or gas-fired generation capable of baseload operation. Further, because of the large block of baseload power provided by PINGP, NMC assumes that if power purchases were used to replace this power over the twenty year replacement term, construction of new generation would still be required, albeit potentially in another state, region or Canada. Therefore, NMC assumes that the generation-related impacts associated with a power purchase alternative would be similar to those evaluated in Sections 7.3.2 and 7.3.3 of this ER. NMC is also adopting by reference the NRC analysis of the environmental impacts from those technologies. Under the purchased power alternative, environmental impacts would still occur, but they would likely originate from a power plant located elsewhere in Minnesota, the region, the U.S., or Canada. However, for purposes of comparative analysis, NMC assumes that overall generation-associated adverse impacts would be no greater than are identified in this ER for the representative gas-fired and coal-fired plant alternatives.

Environmental impacts associated with terminating operations and decommissioning PINGP nonetheless could result in LARGE adverse socioeconomic impacts to the City of Red Wing from loss of tax revenues 20 years earlier than would occur if the PINGP operating license is renewed. Terminating operations and decommissioning PINGP could result in SMALL impacts to the peregrine falcon and paddlefish, a state-listed threatened species, and SMALL impacts to the Higgins eye pearlymussel, a Federal and state-endangered species.

NMC assumes that 100 miles of new 345-kV transmission line on a 150-foot wide ROW in southern Minnesota, potentially affecting approximately 1,800 acres, would be required to import purchased power. Considering the nature of transmission line development and mitigation available, impacts of greatest concern are those related to changes in land use, terrestrial ecological communities, and aesthetics.

Land use and terrestrial ecological habitats in the region where it is assumed the line would be built consists predominantly of rural agricultural land interspersed in some areas with natural vegetation (e.g., forested tracts, wetlands). Therefore, NMC expects these land uses and ecological habitats, which are abundant in the region, would be most affected by transmission line development. Development of the transmission line would limit changes in future land uses on the ROW to those that are compatible with the line, but most agricultural practices and other currently compatible uses could continue.

Establishment of ROW for the transmission line(s) would have little effect on either the amount or value of habitat represented by agricultural land, the predominant habitat expected on lands traversed by these facilities, because compatible agricultural practices could continue. Similarly, open wetlands would be spanned and therefore minimally affected. Depending on route specifics, clearing of forest and shrubland, some of which may qualify as wetland, would also be required. However, hydrologic regimes of wetlands would not be appreciably affected and the conversion of ROW areas currently in forest to open (herbaceous and shrub) habitats can be advantageous to species with affinities for remnant prairie habitats, now rare in the area of interest.

Some visual impairment of the rural landscape would result from development of the transmission line. However, the topography throughout most of southern Minnesota is rolling, and forested tracts occur in some parts of the area. Both of these attributes would act to reduce the viewshed and limit potential for impairment of visual aesthetics. In addition, the presence of transmission line is not out of character for the existing rural southern Minnesota landscape.

Finally, NMC expects that routing of the line could be accomplished such that highly incompatible land uses, important habitats and associated important species, and areas of potentially high impact on visual aesthetics would be recognized and avoided or appropriately mitigated such that important attributes of these resources would not be destabilized.

On the basis of these considerations, NMC concludes that the associated impacts of the transmission line development and operation would be SMALL to MODERATE with respect to land use, ecological resources, and aesthetics. Transmission line development could result in LARGE adverse socioeconomic impacts to the City of Red Wing from loss of tax revenues 20 years earlier than would occur if the PINGP operating license is renewed. Impacts to remaining resources would be of SMALL significance.

### 7.3.2 GAS-FIRED GENERATION

NRC evaluated environmental impacts from gas-fired generation alternatives in the GEIS, focusing on combined-cycle plants. Section 7.2.2.2 presents NMC's reasons for defining the gas-fired generation alternative as a combined-cycle plant on a greenfield site.

In the GEIS Supplement for McGuire Nuclear Station (NRC 2002b), NRC evaluated the environmental impacts of constructing and operating five 482 MWe combined-cycle gas-fired units as an alternative to a nuclear power plant license renewal. NMC has reviewed the NRC analysis, believes it to be sound, and notes that it analyzed more generating capacity than the 1,040 MWe of net power discussed in this analysis.

#### 7.3.2.1 Land Use

Although potential impacts on land use would be location specific and therefore conjectural for a greenfield site, potentially affected areas are predominantly rural agricultural land interspersed in some areas with natural vegetation (e.g., forested tracts and wetlands). Based on information presented in Section 7.2.2.2 of this ER, NMC expects plant development would involve conversion of approximately 41 acres of rural agricultural land and/or natural plant communities abundant in the region to industrial use. Development of offsite infrastructure (i.e., transmission line, gas pipeline), involving approximately 110 acres of ROW, would similarly limit development of future incompatible land uses but compatible land uses, including most agricultural practices, could continue. Considering also that land use impacts would be addressed in siting and designing these facilities, NMC concludes that land use impacts could range from SMALL to MODERATE, depending on site-specific factors.

#### 7.3.2.2 Air Quality

Natural gas is a relatively clean-burning fossil fuel that primarily emits nitrogen oxides ($NO_x$), a regulated pollutant, during combustion. A natural gas-fired plant would also emit small quantities of sulfur oxides ($SO_x$), particulate matter, and carbon monoxide, all of which are regulated pollutants. Carbon dioxide, a greenhouse gas, would also be emitted. Control technology for gas-fired turbines focuses on $NO_x$ emissions. NMC estimates the gas-fired alternative emissions to be as follows (TtNUS 2007b):

$SO_x$ = 83 tons per year

$NO_x$ = 312 tons per year

Carbon monoxide = 409 tons per year

Filterable Particulates = 122 tons per year (all particulates are $PM_{10}$)

In 2005, Minnesota was ranked 25th nationally in sulfur dioxide ($SO_2$) emissions (EIA 2007). Therefore, the electric power plants in 24 states emitted more $SO_2$ than those located in Minnesota. The acid rain requirements of the Clean Air Act 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 Act, the companies must hold enough allowances to cover their annual $SO_2$ emissions. Xcel Energy would need to obtain $SO_2$ credits to operate a fossil-fuel-burning plant at the greenfield site.

In 1998, the EPA promulgated the $NO_x$ State Implementation Plan (SIP) Call regulation that required 22 states, including Minnesota, to reduce their $NO_x$ emissions by over 30 percent to address regional transport of ground-level ozone across state lines (EPA 1998b). The $NO_x$ SIP Call imposes a $NO_x$ "budget" to limit the $NO_x$ emissions from each state. To operate a fossil-fuel-fired plant at the greenfield site, Xcel Energy would also need to obtain enough $NO_x$ credits to cover annual emissions either from the set-aside pool or by buying $NO_x$ credits from other sources.

In addition, Minnesota is one of the states covered by the Clean Air Interstate Rule (CAIR), designed to reduce air pollution that moves across state boundaries. The CAIR, issued March 10, 2005, will permanently cap emissions of sulfur dioxide and nitrogen oxides in the eastern United States when fully implemented (EPA 2006). The CAIR is projected to reduce Minnesota's sulfur dioxide and nitrogen oxide emissions by 36 and 59 percent, respectively, by 2015. Minnesota must achieve the required emission reductions of the CAIR, and Xcel Energy will have to comply with Minnesota's emission reduction program.

$NO_x$ effects on ozone levels, $SO_2$ allowances, and $NO_x$ emission offsets could all be issues of concern for gas-fired combustion. While gas-fired turbine emissions are less than coal-fired boiler emissions, and regulatory requirements are less stringent, the emissions are still substantial. NMC concludes that emissions from the gas-fired alternative at a greenfield site would noticeably alter local air quality, but would not destabilize regional resources (i.e., air quality). Air quality impacts would therefore be MODERATE.

### 7.3.2.3 Waste Management

The solid waste generated from this type of facility would be minimal. NMC concludes that gas-fired generation waste management impacts would be SMALL.

### 7.3.2.4 Ecological Resources

Development of the representative plant at a greenfield site in southern Minnesota would likely result in the loss of approximately 41 acres of terrestrial habitat for onsite plant facilities, and modification of approximately 110 acres of existing offsite terrestrial habitat for a new natural gas supply pipeline and transmission line ROW. Habitat most likely to be affected consists of rural agricultural land interspersed in some areas with natural vegetation communities abundant in the region (e.g., forested tracts and wetlands).

Impacts associated with transmission line and pipeline development would be similar to those described in Section 7.3.1 for the transmission line(s) assumed to be needed for the purchase power alternative.

The most significant potential impacts to aquatic communities relate to operation of the cooling water system. However, the cooling system for the plant would be designed and operated in compliance with the Clean Water Act (CWA), including National Pollutant Discharge Elimination System (NPDES) limitations for physical and chemical parameters of potential concern and provisions of CWA Sections 316(a) and 316(b), which are respectively established to ensure appropriate protection of aquatic communities from thermal discharges and the location and operation of cooling water intakes.

In view of these considerations and assumptions of this assessment, NMC expects that impacts on ecological resources would not noticeably alter any important attribute of the resource, particularly if located on agricultural lands, consistent with NRC's definition of SMALL impact significance. However, considering the uncertainties associated with greenfield development, NMC concludes that impacts on ecological resources could be of SMALL to MODERATE significance.

### 7.3.2.5 Socioeconomics

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

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

• net change in permanent jobs, tax revenues, and economic activity attributable to gas-fired plant operation and termination of PINGP operations.

Although the area south of Minneapolis is predominantly rural, it is within commuting distance of relatively large population centers, including Minneapolis-St. Paul, Mankato, and Rochester. Considering the proximity of these sources of labor and services, NMC expects that most of the construction workforce would commute and relatively few would relocate to small communities near the plant such that significant demand for housing or public services would result. Associated socioeconomic impacts during construction are therefore expected to be SMALL, regardless of plant location. Considered together with impacts of the no action "base case" (terminating operations and decommissioning PINGP), the greenfield siting alternative could result in LARGE adverse socioeconomic impacts to the City of Red Wing from loss of tax revenues 20 years earlier than would occur if the PINGP operating licenses were not renewed. NMC concludes that overall socioeconomic impact of the representative plant at the assumed greenfield site would be of MODERATE to LARGE significance.

#### 7.3.2.6 Aesthetics

Potential aesthetic impacts of construction and operation of a gas-fired plant include visual impairment resulting from the presence of a industrial facility and associated ROWs, particularly 200-foot high exhaust stacks and condensate plume from the cooling tower. However, the topography throughout most of southern Minnesota is rolling and forested tracts are common in some areas. Both of these factors act to reduce the viewshed and limit potential for impairment of visual aesthetics. NMC assumes that adequate buffer and vegetation screens would be provided at the plant site as needed to moderate visual and noise impacts. Considering also that the location and design of the plant and associated offsite infrastructure would be decided with consideration of potential adverse aesthetic effects, NMC concludes that aesthetic impact could range from SMALL to MODERATE, depending on location.

#### 7.3.2.7 Other Impacts

Cooling water intake and discharge flows, potable and service water use, and wastewater discharges for the representative gas-fired plant would be substantially lower than currently result from PINGP operation, due to less power derived from a steam cycle, use of a closed-cycle cooling system, and smaller operating workforce. Cooling water, wastewater, and stormwater discharges would be regulated under the CWA and corresponding state programs by NPDES permit. Potential impacts on water quality during construction would also be subject to regulatory controls.

Operation of the gas-fired alternative would generate only small quantities of municipal and industrial waste, including spent catalyst used for $NO_x$ control, which would be disposed of in accordance with applicable regulations at a permitted offsite disposal facility.

NRC cites risk of accidents to workers and public risks (e.g., cancer, emphysema) from the inhalation of toxics and particulates associated with air emissions as potential risks to human health associated with the gas-fired generation alternative (NRC 1996a). NMC assumes that regulatory requirements imposed on facility design and operations under the authority of the Occupational Safety and Health Act, Clean Air Act, and related statutes are designed to provide an appropriate level of protection to workers and the public with respect to these risks.

The representative gas-fired plant and associated gas supply pipeline and transmission line would be located with consideration of cultural resources, and NMC expects that appropriate measures would be taken to avoid, recover or provide other mitigation for loss of any resources discovered during onsite or offsite construction.

NMC concludes that the potential adverse impacts of this alternative on water quality and use, threatened and endangered species, human health, and cultural resources would likely be SMALL.

### 7.3.3 COAL-FIRED GENERATION

NRC evaluated environmental impacts from coal-fired generation alternatives in the GEIS (NRC 1996a). NRC concluded that construction impacts could be substantial, due in part to the large land area required (which can result in natural habitat loss) and the large workforce needed. NRC identified 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 NMC has defined in Section 7.2.2.3 would be located at a greenfield site.

#### 7.3.3.1 Land Use

Although potential impacts on land use would be location specific and therefore conjectural for a greenfield site, potentially affected areas are predominantly rural agricultural land interspersed in some areas with natural vegetation (e.g., forested tracts and wetlands) all of which are abundant in the region. NMC expects the total site would consist of approximately 170 acres (TtNUS 2007a). Land uses would also be precluded on 180 acres onsite for waste disposal (TtNUS 2007b). Offsite, an estimated 60 acres of land would be converted to transportation use (rail spur) and 90 acres would be converted to utility use (transmission line) (TtNUS 2007a). Similarly, development of future incompatible land uses would be precluded on the transmission ROW, but compatible land uses, including most agricultural practices, could continue. In view of the large amount of land affected and the permanent land use change from the landfill, NMC concludes that land use impacts would be clearly noticeable. Considering also the assumption that environmental review, siting and design of these facilities would ensure that land uses in affected areas would not be destabilized, NMC concludes that land use impacts would be MODERATE.

#### 7.3.3.2 Air Quality

A coal-fired plant would emit $SO_x$, $NO_x$, particulate matter, and carbon monoxide, all of which are regulated pollutants. Non-regulated pollutants including carbon dioxide, a greenhouse gas, and mercury, would also be emitted. As Section 7.2.1.1 indicates, NMC has assumed a plant design that would minimize air emissions through a combination of boiler technology and post-combustion pollutant removal. NMC estimates the coal-fired alternative emissions to be as follows (TtNUS 2007b):

$SO_x$ = 1,815 tons per year

$NO_x$ = 848 tons per year

Carbon monoxide = 1,178 tons per year

Mercury = 0.2 tons per year

Particulates:

Total suspended particulates = 152 tons per year

$PM_{10}$ (particulates having a diameter of less than 10 microns) = 35 tons per year

The Section 7.3.2.2 discussion of regional air quality is applicable to the coal-fired generation alternative. $SO_2$ emission allowances, low $NO_x$ burners, overfire air, fabric filters, and scrubbers are regulatory-imposed mitigation measures. As such, NMC 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.

#### 7.3.3.3 Waste Management

NMC concurs with the GEIS assessment that the coal-fired alternative would generate substantial amounts of solid waste. The coal-fired plant would annually consume approximately 4,700,000 tons of coal with an ash content of 6.47 percent. After combustion, 30 percent of this ash, approximately 91,000 tons per year, would be marketed for beneficial reuse. The remaining ash, approximately 210,000 tons per year, would be collected and disposed of onsite. In addition, approximately 77,000 tons of scrubber sludge would be disposed of onsite each year (based on annual lime usage of nearly 65,000 tons). NMC estimates that ash and scrubber waste disposal over a 40-year plant life would require approximately 180 acres (a square area with sides of approximately 2,800 feet). While only half this waste volume and acreage would be attributable to the 20-year license renewal period alternative, the total numbers are pertinent as a cumulative impact (TtNUS 2007b).

NMC contends that, with proper siting coupled with current waste management and monitoring practices, waste disposal would not destabilize any resources. After closure of the waste site and revegetation, the land would be available for other uses. For these reasons, NMC contends that waste management for the coal-fired alternative would have MODERATE impacts; the impacts of increased waste disposal would be noticeable, but would not destabilize any important resource, and further mitigation would be unwarranted.

#### 7.3.3.4 Ecological Resources

Development of the representative coal-fired plant at a greenfield site in southern Minnesota would likely result in the loss of 350 acres of terrestrial habitat for onsite plant facilities and air emission control waste landfill, loss of approximately 60 acres of offsite habitat for the rail line, and modification of 90 acres of offsite terrestrial habitat for a new transmission line to serve the plant. While the amount of habitat affected would be larger, the nature of impacts would be the same as described for the gas-fired alternative (Section 7.3.2).

The most significant potential impacts to aquatic communities relate to operation of the cooling water system, but regulatory controls would be expected to ensure appropriate protection of aquatic communities from thermal discharges and cooling water intake structures. In addition, because the plant is assumed to use closed-cycle cooling, the cooling water intake and discharge flows would be lower than that of PINGP, the impact from which is considered to be SMALL.

For the same reasons provided with respect to the gas-fired alternative, NMC concludes that impacts on ecological resources from the representative coal-fired plant could be of SMALL to MODERATE significance for the greenfield site option.

#### 7.3.3.5 Socioeconomics

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

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

• net change in permanent jobs, tax revenues, and economic activity attributable to gas-fired plant operation and termination of PINGP operations.

As indicated for the gas-fired alternative, NMC expects that socioeconomic impacts from construction to be SMALL regardless of location. Considered together with impacts of the no action “base case” (terminating operations and decommissioning PINGP), the greenfield siting alternative could result in LARGE adverse socioeconomic impacts to the City of Red Wing from loss of tax revenues 20 years earlier than would occur if the PINGP operating licenses were not renewed.  NMC concludes that the overall socioeconomic impact of the representative plant at the greenfield site would be of MODERATE to LARGE significance.

#### 7.3.3.6 Aesthetics

Potential aesthetic impacts of construction and operation of a coal-fired plant include visual impairment resulting from the presence of a industrial facility, particularly a 500-foot high exhaust stack and condensate plume from the cooling tower. However, the topography throughout most of southern Minnesota is rolling and forested tracts are common in some areas. Both of these factors act to reduce the viewshed and limit potential for impairment of visual aesthetics from onsite and offsite infrastucture. NMC assumes that adequate buffer and vegetation screens would be provided at the plant site as needed to reduce visual and noise impacts. Considering also that the location and design of the plant and associated offsite infrastructure would be decided with consideration of potential adverse aesthetic effects, NMC concludes that aesthetic impact could range from SMALL to MODERATE, depending on location.

#### 7.3.3.7 Other Impacts

NMC expects that cooling water intake and discharge flows, potable and service water use, and wastewater discharges for the representative coal-fired plant, which has a closed-cycle cooling system would be lower than current PINGP operations, the impact from which is considered to be small. Cooling water, wastewater, and stormwater discharges would be regulated under the CWA and corresponding state programs by NPDES permit. Potential impacts on water quality during construction would also be subject to regulatory controls.

In the GEIS, NRC cites risk of accidents to workers and public risks (e.g., cancer, emphysema) from the inhalation of toxics and particulates associated with air emissions as potential risks to human health associated with the coal-fired generation alternative (NRC 1996a). NMC assumes that regulatory requirements imposed on facility design and operations under the authority of the Occupational Safety and Health Act, Clean Air Act, and related statutes are designed to provide an appropriate level of protection to workers and the public with respect to these risks.

The representative coal-fired plant and associated transmission line would be located with consideration of cultural resources, and NMC expects that appropriate measures would be taken to avoid, recover or provide other mitigation for loss of any resources discovered during onsite or offsite construction.

NMC concludes that the potential adverse impacts of this alternative on water quality and use, human health, threatened and endangered species, and cultural resources would likely be SMALL.

# TABLE 7.2-1
# GAS-FIRED ALTERNATIVE

| Characteristic | Basis |
|---|---|
| Unit size = 520 MWe ISO rating net[a] | Manufacturer's standard size gas-fired combined-cycle plant that is < PINGP net capacity - 1,044 MWe |
| Unit size = 542 MWe ISO rating gross[a] | Calculated based on 4 percent onsite power |
| Number of units = 2 | Assumed |
| Fuel type = natural gas | Assumed |
| Fuel heating value = 1,008 Btu/ft$^3$ | 2004 value for gas used in Minnesota (EIA 2007) |
| Fuel $SO_x$ content = 0.0034 lb/MMBtu | EPA 2000, Table 3.1-2a |
| $NO_x$ control = selective catalytic reduction (SCR) | Selected for $NO_x$ emissions control in the feasibility study (UE 2002) |
| Fuel $NO_x$ content = 0.0128 lb/MMBtu | Typical for large SCR-controlled gas fired units (EPA 2000) |
| Fuel CO content = 0.0168 lb/MMBtu | Typical for large SCR-controlled gas fired units (EPA 2000) |
| Fuel $PM_{10}$ content = 0.005 lb/MMBtu | EPA 2000, Table 3.1-2a |
| Heat rate = 6,040 Btu/kWh | (Chase and Kehoe 2000) |
| Capacity factor = 0.85 | Assumed based on performance of modern plants |

a. The difference between "net" and "gross" is electricity consumed onsite.

| | | |
|---|---|---|
| Btu | = | British thermal unit |
| CO | = | carbon monoxide |
| 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 |
| kWh | = | kilowatt hour |
| Lb | = | pound |
| MM | = | million |
| MWe | = | megawatt electric |
| $NO_X$ | = | nitrogen oxides |
| $PM_{10}$ | = | particulates having diameter of 10 microns or less |
| SCR | = | selective catalytic reduction |
| $So_x$ | = | sulfur oxides |
| ≤ | = | less than or equal to |

# TABLE 7.2-2
# COAL-FIRED ALTERNATIVE

| Characteristic | Basis |
|---|---|
| Unit size = 520 MWe ISO rating net[a] | Calculated to be ≤ PINGP net capacity – 1,044 MWe |
| Unit size = 553 MWe ISO rating gross[a] | Calculated based on 6 percent onsite power |
| Number of units = 2 | Assumed |
| Boiler type = tangentially fired, dry-bottom | Minimizes nitrogen oxides emissions (EPA 1998a) |
| Fuel type = sub-bituminous, pulverized coal | Typical for coal used in Minnesota |
| Fuel heating value = 8,914 Btu/lb | 2004 value for coal used in Minnesota (EIA 2007) |
| Fuel ash content by weight = 6.47 percent[b] | 2001 value for coal used in Minnesota (EIA 2007) |
| Fuel sulfur content by weight = 0.44 percent | 2002 value for coal used in Minnesota (EIA 2007) |
| 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) |
| Heat rate = 10,200 Btu/kWh | Typical for coal-fired, single-cycle steam turbines (EIA 2002) |
| Capacity factor = 0.85 | Typical for large coal-fired units |
| $NO_x$ control = low $NO_x$ burners, overfire air and selective catalytic reduction (95 percent reduction) | Best available and widely demonstrated for minimizing $NO_x$ emissions (EPA 1998a) |
| Particulate control = fabric filters (baghouse-99.9 percent removal efficiency) | Best available for minimizing particulate emissions (EPA 1998a) |
| $SO_x$ control = Wet scrubber - lime (95 percent removal efficiency) | Best available for minimizing $SO_x$ emissions (EPA 1998a) |

a. The difference between “net” and “gross” is electricity consumed onsite.
b. The 2002 average percent ash for coal used in Minnesota is not available.

| | | |
|---|---|---|
| Btu | = | British thermal unit |
| CO | = | carbon monoxide |
| 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 |
| kWh | = | kilowatt hour |
| NSPS | = | New Source Performance Standard |
| lb | = | pound |
| MWe | = | megawatt |
| $NO_x$ | = | nitrogen oxides |
| $SO_x$ | = | oxides of sulfur |
| ≤ | = | less than or equal to |

## 7.4 REFERENCES

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

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# 8.0 COMPARISON OF ENVIRONMENTAL IMPACTS OF LICENSE RENEWAL WITH THE ALTERNATIVES

**NRC**

**"To the extent practicable, the environmental impacts of the proposal and the alternatives should be presented in comparative form..." 10 CFR 51.45(b)(3) as adopted by 51.53(c)(2)**

Nuclear Management Company, LLC (NMC) presents its evaluations of the environmental impacts associated with Prairie Island Nuclear Generating Plant (PINGP) operating license renewal (the proposed action) and those associated with selected alternatives in Chapter 4 and Chapter 7 of this ER, respectively. In this chapter, NMC provides a comparative summary of these impacts. The environmental impacts comparison addresses Category 2 issues associated with the proposed action and additional issues the U.S Nuclear Regulatory Commission (NRC) identifies in the Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996, Section 8.1) as major considerations in an alternatives analysis. Inclusion of these additional issues therefore established a basis for comparison of relevant impacts among alternatives. NMC provides a comparative summary of its conclusions regarding these issues in Table 8-1, and a more detailed comparison in Table 8-2.

As indicated in Tables 8-1 and 8-2, environmental impacts of the proposed action (PINGP license renewal) are expected to be SMALL for all impact categories. In contrast, NMC expects that socioeconomic impacts would be LARGE for the no-action alternative (NRC decision not to renew the PINGP operating license), considered with or without development of replacement generation facilities. Expected adverse environmental impacts include the potential loss of substantial tax revenues by the City of Red Wing, and Goodhue County from termination of PINGP operations 20 years sooner than if its license is renewed. Notable adverse impacts in the areas of land use, air quality, ecological resources, waste management, socioeconomics, and aesthetics may result from replacement of PINGP generating capacity with an alternative generating source, depending on the alternative selected.

In summary, NMC's analysis indicates that renewal of the PINGP operating licenses is preferred from an environmental standpoint. With respect to NRC's decision-making standard at 10 CFR 51.95(c)(4), the analysis supports a conclusion that the option of renewing PINGP operating license should be preserved.

**TABLE 8-1**
**IMPACTS COMPARISON SUMMARY**

| | | | No Action Alternatives | | |
|---|---|---|---|---|---|
| **Impact** | **Proposed Action (License Renewal)** | **Base (Decommissioning)** | **With Coal-Fired Generation** | **With Gas-Fired Generation** | **With Purchased Power** |
| Land Use | SMALL | SMALL | MODERATE | SMALL to MODERATE | SMALL to MODERATE |
| Water Quality | SMALL | SMALL | SMALL | SMALL | SMALL |
| Air Quality | SMALL | SMALL | MODERATE | MODERATE | MODERATE |
| Ecological Resources | SMALL | SMALL | SMALL to MODERATE | SMALL to MODERATE | SMALL to MODERATE |
| Threatened or Endangered Species | SMALL | SMALL | SMALL | SMALL | SMALL |
| Human Health | SMALL | SMALL | SMALL | SMALL | SMALL |
| Socioeconomics | SMALL | LARGE | MODERATE to LARGE | MODERATE to LARGE | MODERATE to LARGE |
| Waste Management | SMALL | SMALL | MODERATE | SMALL | SMALL to MODERATE |
| Aesthetics | SMALL | SMALL | SMALL to MODERATE | SMALL to MODERATE | SMALL to MODERATE |
| Cultural Resources | SMALL | SMALL | SMALL | SMALL | SMALL |

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.
MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.
LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource.
10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3.

## TABLE 8-2
## IMPACTS COMPARISON DETAIL

| | | No-Action Alternatives | | |
|---|---|---|---|---|
| **Proposed Action (License Renewal)** | **Base (Decommissioning)** | **With Coal-Fired Generation** | **With Gas-Fired Generation** | **With Purchased Power** |
| | | **Alternative Descriptions** | | |
| PINGP license renewal for 20 years beyond the current expiration dates of 2013 and 2014 for Units 1 and 2, respectively. | Terminate operations and decommission PINGP following license expiration in 2013 and 2014 for Units 1 and 2, respectively. Adopting by reference NRC impacts of associated activities provided in the GEIS Chapter 7. | New construction at a greenfield site. | New construction at a greenfield site. | Would involve construction of new generation capacity in Minnesota or other states. |
| | | New rail spur (60 acres) | Construction of a new gas pipeline and transmission line disturbing as much as 110 acres. May require upgrades to existing pipelines. | |
| | | New switchyard and transmission lines | New switchyard and transmission lines | Construct approximately 100 miles of transmission lines. |
| | | Two 520 MW (net) tangentially-fired, dry bottom unit; capacity factor 0.85 | Two 520 MW (net) (Combined-cycle turbines to be used); capacity factor 0.85 | |
| | | New cooling water intake/ discharge system | New cooling water intake/ discharge system | |
| | | Pulverized bituminous coal, 8,914 Btu/pound; 10,200 Btu/kWh; 6.47% ash; 0.44% sulfur; 7.2 lb/ton nitrogen oxides; 4.7 million tons coal/yr | Natural gas, 1,008 Btu/$ft^3$; 6,040 Btu/kWh; 0.0034 lb sulfur/MMBtu; 0.0128 lb $NO_x$/MMBtu; 48.3 million $ft^3$ gas/yr | |

## TABLE 8-2 (CONTINUED)
## IMPACTS COMPARISON DETAIL

| | | No Action Alternative | | |
|---|---|---|---|---|
| **Proposed Action (License Renewal)** | **Base (Decommissioning)** | **With Coal-Fired Generation** | **With Gas-Fired Generation** | **With Purchased Power** |
| | | Low $NO_x$ burners, overfire air and selective catalytic reduction (95% $NO_x$ reduction efficiency) | Selective catalytic reduction with steam/water injection | |
| | | Wet scrubber – lime/limestone desulfurization system (95% $SO_x$ removal efficiency); 64,675 tons lime/yr | | |
| | | Fabric filters (99.9% particulate removal efficiency) | | |
| 582 permanent and 103 long-term contract workers | | 1,700 construction workers and 120 permanent workers (Section 7.2.2.3) | 629 construction workers and 35 permanent workers(Section 7.2.2.2) | |
| **Land Use Impacts** | | | | |
| SMALL – Adopting by reference Category 1 issue findings (Appendix A, Table A-1, Issues 52, 53). Offsite land use impacts as a result of license renewal and refurbishment would be minimal as a result of established land use patterns (Section 4.14, Issues 68 and 69). | SMALL – Not an impact evaluated by GEIS (NRC 1996) | MODERATE – 350 acres required for the powerblock and waste disposal. 150 acres required for transmission line and rail spur (Section 7.3.3.1). | SMALL to MODERATE – 41 acres for facility; 110 acres for pipeline and transmission line (Section 7.3.2.1). New gas pipeline would be built to connect with existing gas pipeline corridor. | SMALL to MODERATE – transmission facilities could be constructed to avoid highly incompatible land uses (Section 7.3.1). |

## TABLE 8-2 (CONTINUED)
## IMPACTS COMPARISON DETAIL

| **Proposed Action (License Renewal)** | **Base (Decommissioning)** | **No Action Alternative** | | |
|---|---|---|---|---|
| | | **With Coal-Fired Generation** | **With Gas-Fired Generation** | **With Purchased Power** |
| | | **Water Quality Impacts** | | |
| SMALL – Adopting by reference Category 1 Issue findings (Appendix A, Table A-1, Issues 1-3, 6-12, 14-16, and 31). Two Category 2 groundwater issues not applicable (Section 4.2, Issues 35 and 39).<br>Under normal conditions PINGP withdrawals do not affect surface water and groundwater quality or conflict with water use (Section 4.2, Issues 13, 33, and 34) | SMALL – Adopting by reference Category 1 issue finding (Appendix A, Table A-1, Issue 89). | SMALL – Construction impacts minimized by use of best management practices.<br>(Section 7.3.3.7) | SMALL – Reduced cooling water demands, inherent in combined-cycle design (Section 7.3.2.7) | SMALL– Impacts would be similar to the impacts of baseload alternatives (Sections 7.3.2 and 7.3.3) |
| | | **Air Quality Impacts** | | |
| SMALL – Adopting by reference Category 1 issue finding (Appendix A, Table A-1, Issue 51**).** Air quality impacts as a result of refurbishment would be temporary and localized (Section 4.8, Issue 50). | SMALL – Adopting by reference Category 1 issue findings (Appendix A, Table A-1, Issue 88) | MODERATE –<br>1,815 tons $SO_x$/yr<br>848 tons $NO_x$/yr<br>1,178 tons CO/yr<br>152 tons TSP/yr<br>35 tons $PM_{10}$/yr<br>0.2 tons Hg/yr<br>(Section 7.3.3.2) | MODERATE –<br>83 tons $SO_x$/yr<br>312 tons $NO_x$/yr<br>409 tons CO/yr<br>122 tons $PM_{10}$/yr[a]<br>(Section 7.3.2.2) | MODERATE – Impacts would be similar to the impacts of baseload alternatives (Sections 7.3.2 and 7.3.3) |

## TABLE 8-2 (CONTINUED)
## IMPACTS COMPARISON DETAIL

| | | No Action Alternative | | |
|---|---|---|---|---|
| **Proposed Action (License Renewal)** | **Base (Decommissioning)** | **With Coal-Fired Generation** | **With Gas-Fired Generation** | **With Purchased Power** |
| | | **Ecological Resource Impacts** | | |
| SMALL – Adopting by reference Category 1 issue findings (Appendix A, Table A-1, Issues 15-24, 28-30, 43, 45-48). Entrainment, impingement, and heat shock impacts are SMALL (Section 4.3, Issue 25; Section 4.4, Issue 26; Section 4.5, Issue 27); Refurbishment activities would occur in locations devoid of ecological resources (Section 4.6, Issue 40). | SMALL – Adopting by reference Category 1 issue finding (Appendix A, Table -1, Issue 90) | SMALL to MODERATE – 500 acres could be required for plant facilities and ash/sludge disposal over 20-year license renewal term. (Section 7.3.3.4). | SMALL to MODERATE – Construction of new facilities could alter 41 acres and new pipeline and transmission line ROW could impact 110 acres (Section 7.3.2.4). | SMALL to MODERATE – Impacts would be similar to the impacts of baseload alternatives (Sections 7.2.2 and 7.2.3) |

## TABLE 8-2 (CONTINUED)
## IMPACTS COMPARISON DETAIL

| | | No Action Alternative | | |
|---|---|---|---|---|
| **Proposed Action (License Renewal)** | **Base (Decommissioning)** | **With Coal-Fired Generation** | **With Gas-Fired Generation** | **With Purchased Power** |
| **Threatened or Endangered Species Impacts** | | | | |
| SMALL – Three state- or federally-listed threatened or endangered species are known to occur in the vicinity of the PINGP site or along the transmission corridors. A pair of Peregrine falcons has nested in a nest box on the Unit 1 containment dome since 1997. Higgins' eye pearlymussels have been cultured and recently re-introduced into lower Pool 4 and upper Pool 3. Biologists conducting fish population studies in Sturgeon Lake over the last several decades have occasionally collected individual paddlefish (Section 4.7, Issue 49). | MODERATE – Removal of the containment buildings would eliminate one of only 25 successful nesting sites that currently exist in the state. Adverse impacts would be SMALL with mitigation (Section 7.1.1). | SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats. | SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats. | SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats. |

## TABLE 8-2 (CONTINUED)
## IMPACTS COMPARISON DETAIL

| | | No Action Alternative | | |
|---|---|---|---|---|
| **Proposed Action (License Renewal)** | **Base (Decommissioning)** | **With Coal-Fired Generation** | **With Gas-Fired Generation** | **With Purchased Power** |
| | | **Human Health Impacts** | | |
| SMALL – Adopting by reference Category 1 issues (Appendix A, Table A-1, Issues 54-56, 58, 61, 62).<br>Risk due to microbiological organisms minimal because the system undergoes periodic treatments to control (Section 4.9, Issue 57)<br>Risk due to transmission-line induced currents minimal due to conformance with consensus code (Section 4.10, Issue 59). | SMALL – Adopting by reference Category 1 issue finding (Appendix A, Table A-1, Issue 86) | SMALL – Adopting by reference GEIS conclusion that risks such as cancer and emphysema from emissions are likely (NRC 1996) | SMALL – Adopting by reference GEIS conclusion that some risk of cancer and emphysema exists from emissions (NRC 1996) | SMALL– Impacts would be similar to the impacts of baseload alternatives (Sections 7.3.2 and 7.3.3) |

# TABLE 8-2 (CONTINUED)
# IMPACTS COMPARISON DETAIL

| | | No Action Alternative | | |
|---|---|---|---|---|
| **Proposed Action (License Renewal)** | **Base (Decommissioning)** | **With Coal-Fired Generation** | **With Gas-Fired Generation** | **With Purchased Power** |
| | | **Socioeconomic Impacts** | | |
| SMALL – Adopting by reference Category 1 issue findings (Appendix A, Table A-1, Issues 64, 67, 91).<br>Existing temporary and permanent housing available minimizes potential for housing impacts. (Section 4.11, Issue 63).<br>Capacity of public water supply and transportation infrastructure minimizes potential for related impacts (Section 4.12, Issue 65 and Section 4.15, Issue 70). The refurbishment workforce would not relocate families due to the short duration of the refurbishment (Section 4.13, Issue 66). License renewal and refurbishment not expected to influence area land-use pattern, but would continue beneficial impact on county (Section 4.14, Issues 68, 69). | LARGE – Large impacts from the loss of tax revenue for the City of Red Wing (Section 7.1.1). | MODERATE to LARGE– Proximity to large population centers would result in SMALL impacts at the location of the representative plant. LARGE impacts from the reduction in tax revenue for the City of Red Wing (Section 7.3.3.5). | MODERATE to LARGE– Proximity to large population centers would result in SMALL impacts at the location of the representative plant. LARGE impacts from the reduction in tax revenue for the City of Red Wing (Section 7.3.2.5). | MODERATE to LARGE – Impacts would be similar to the impacts of baseload alternatives (Sections 7.3.2 and 7.3.3) |

# TABLE 8-2 (CONTINUED)
# IMPACTS COMPARISON DETAIL

| | | No Action Alternative | | |
|---|---|---|---|---|
| **Proposed Action (License Renewal)** | **Base (Decommissioning)** | **With Coal-Fired Generation** | **With Gas-Fired Generation** | **With Purchased Power** |
| | | **Waste Management Impacts** | | |
| SMALL – Adopting by reference Category 1 issue findings (Appendix A, Table A-1, Issues 77-85) | SMALL – Adopting by reference Category 1 issue finding (Appendix A, Table A-1, Issue 87) | MODERATE – 210,000 tons of coal ash per year and 77,000 tons of scrubber sludge per year would require 90 acres over 20-year license renewal term. Industrial waste generated annually (Section 7.3.3.3). | SMALL – Almost no waste generation (Section 7.3.2.3) | SMALL to MODERATE – Impacts would be similar to the impacts of baseload alternatives (Sections 7.3.2 and 7.3.3) |
| | | **Aesthetic Impacts** | | |
| SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 72-74) | SMALL – Not an impact evaluated by GEIS (NRC 1996) | SMALL to MODERATE – The coal-fired power blocks and the exhaust stacks would be visible from a moderate offsite distance (Section 7.3.3.6). | SMALL to MODERATE – Steam turbines and stacks would create visual impacts (Section 7.3.2.6). | SMALL to MODERATE – Impacts would be similar to the impacts of baseload alternatives (Sections 7.3.2 and 7.3.3) |
| | | **Cultural Resource Impacts** | | |
| SMALL – No known impacts to archeological or cultural resources on PINGP site or transmission line corridors (Section 4.16, Issue 71). | SMALL – Not an impact evaluated by GEIS (NRC 1996) | SMALL – Impacts to cultural resources would be avoided (Section 7.3.2.7). | SMALL – Impacts to cultural resources would be avoided (Section 7.3.3.7). | SMALL – Impacts would be similar to the impacts of baseload alternatives (Sections 7.3.2 and 7.3.3) |

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.
MODERATE Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource. 10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3.
LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource.

Btu = British thermal unit
$ft^3$ = cubic foot
gal = gallon
GEIS = Generic Environmental Impact Statement (NRC 1996)
kW-h = kilowatt-hour
lb = pound
MM = million
MW = megawatt
$NO_x$ = nitrogen oxide
$PM_{10}$ = particulates having diameter less than 10 microns
SHPO = State Historic Preservation Officer
$SO_x$ = oxides of sulfur
TSP = total suspended particulates
yr = year

a. All TSP for gas-fired alternative is $PM_{10}$.

## 8.1 REFERENCES

NRC (U.S. Nuclear Regulatory Commission). 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS), Volumes 1 and 2, NUREG-1437. Washington, D.C. May.

# 9.0 STATUS OF COMPLIANCE

## 9.1 PROPOSED ACTION

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

### 9.1.1 GENERAL

Table 9.1-1 lists environmental authorizations that Northern States Power (NSP) has obtained for current Prairie Island Nuclear Generating Plant (PINGP) operations. In this context Nuclear Management Company, LLC (NMC) defines "authorizations" to include any permits, licenses, approvals, or other entitlements. NMC expects NSP to continue renewing these authorizations during the current license period and through the U.S. Nuclear Regulatory Commission (NRC) license renewal period, and complying with the Red Wing Zoning Ordinance for General Industrial Use. Because the NRC regulatory focus is prospective, Table 9.1-1 does not include authorizations that NMC obtained for past activities that did not include continuing obligations such as building and construction permits.

Before preparing the application for license renewal, NMC conducted an assessment to identify any new and significant environmental information (Chapter 5). The assessment included interviews with NMC, NSP, and Xcel Energy experts, review of PINGP environmental documentation, and communication with state and federal environmental protection agencies. Based on this assessment, NMC concludes that PINGP is in compliance with applicable environmental standards and requirements.

Table 9.1-2 lists additional environmental authorizations and consultations related to NRC renewal of the PINGP license to operate. As indicated, NMC anticipates needing relatively few such 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 agency action is not likely to jeopardize any species that is listed, or proposed for listing as endangered, or threatened. Depending on the action involved, the Act requires consultation with the U.S. Fish and Wildlife Service (FWS) regarding effects on non-marine species, the National Marine Fisheries Service (NMFS) for marine species, or both. The FWS and NMFS have issued joint procedural regulations at 50 CFR 402, Subpart B, that address consultation, and FWS maintains the joint list of threatened and endangered species at 50 CFR 17.

As discussed in Section 4.7 of this Environmental Report (ER), NMC does not expect the continued operation of PINGP to affect the population of any state or federally listed threatened or endangered species or natural communities in the vicinity of the PINGP site. Although not required of an applicant by federal law or NRC regulation, NMC has chosen to invite comment from federal and state agencies regarding potential effects that PINGP license renewal might have on threatened or endangered species. Attachment C includes copies of NMC correspondence with FWS and the Minnesota Department of Natural Resources, Ecological Resources Division, Natural Heritage and Nongame Research Program.

### 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, prior to issuing the license, take into account the effect of the undertaking on historic properties and to afford the Advisory Council on Historic Preservation an opportunity to comment on the undertaking. Council regulations provide for the State Historic Preservation Officer (SHPO) to have a consulting role (35 CFR 800.2). Although not required of an applicant by federal law or NRC regulation, NMC has chosen to invite comment by the Minnesota SHPO. Attachment D contains a copy of NMC’s letter to the Minnesota SHPO.

### 9.1.4 WATER QUALITY (401) CERTIFICATION

Federal Clean Water Act Section 401 requires an applicant for a federal license to conduct an activity that might result in a discharge into navigable waters to provide the licensing agency a certification from the state that the discharge will comply with applicable Clean Water Act requirements (33 USC 1341). NRC has indicated in its Generic Environmental Impact Statement for License Renewal (NRC 1996, Section 4.2.1.1) that issuance of a National Pollutant Discharge Elimination System (NPDES) permit implies certification by the state. NMC is applying to NRC for license renewal to continue PINGP operations. Consistent with the GEIS, NMC is providing PINGP's NPDES permit as evidence of state water quality (401) certification (Attachment B).

### 9.1.5 STATE OF MINNESOTA ENVIRONMENTAL REVIEW PROGRAM

The Minnesota Public Utility Commission (MPUC) requires a Certificate of Need (CON) application to allow additional dry cask storage at the Independent Spent Fuel Storage Installation (ISFSI) on the PINGP site. Minnesota Statute Chapter 216B.243 Subdivision 3b(b) requires that the CON address the impacts of continued operation during the period covered by the renewed license. Minnesota Statute Chapter 116C.83 Subdivision 6(b) requires that an environmental impact statement (EIS) be prepared by the Minnesota Environmental Quality Board (MEQB) pursuant to the requirements of Chapter 116D for the construction and operation of an ISFSI. This EIS will be prepared by the MEQB and submitted to the MPUC for consideration in the MPUC's CON determination.

## 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, and purchased power alternatives discussed in Section 7.2.2 could be constructed and operated to comply with applicable environmental quality standards and requirements. NMC notes that increasingly stringent air quality protection requirements could make the construction of a large fossil-fueled power plant infeasible in many locations. NMC also notes that the U.S. Environmental Protection Agency has revised requirements for design and operation of cooling water intake structures at new and existing facilities (40 CFR 125 Subparts I and J). These requirements could necessitate construction of cooling towers for the coal- and gas-fired alternatives if surface water were used for once-through condenser cooling.

**TABLE 9.1-1**
**ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT PINGP OPERATIONS**

| Agency | Authority | Requirement | Number | Expiration Date | Activity Covered |
|---|---|---|---|---|---|
| | | **Federal and State Requirements** | | | |
| Minnesota Department of Health | Minnesota Rules 4740.2010 through 4741.2120 | Certification | 027-049-218 | 12/23/2009 | Certification of the Environmental Laboratory |
| Minnesota Department of Natural Resources | 10 U.S.C. 2668 | Amended Permit (amended as needed) | 80-5082 | NA | Construction of intake canal system. |
| Minnesota Department of Natural Resources | 10 U.S.C. 2668 | Amended Permit (amended as needed) | 80-5081 | NA | Construction of discharge canal system. |
| Minnesota Department of Natural Resources | MN Rules Chapters 97A & 6212.1400 | Division of Fish and Wildlife Special Permit | 14658 | 12/31/2008 | Collect fish and ichthyo - plankton for biological evaluation. |
| Minnesota Department of Natural Resources | MN Rules 6216.1400 and 6212.1500 | Division of Fish and Wildlife Special Permit | 14567 | 12/31/2008 | Collect native fish for aquaria |
| Minnesota Department of Natural Resources | MN Rules 6216.0100 to 6216.0600 to | Permit | 159 | 12/31/2009 | Collect and possess zebra mussels from Lakes Zumbro and Pepin for control studies at plant |

**TABLE 9.1-1**
**ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT PINGP OPERATIONS (CONTINUED)**

| Agency | Authority | Requirement | Number | Expiration Date | Activity Covered |
|---|---|---|---|---|---|
| | | **Federal and State Requirements** | | | |
| Minnesota Department of Natural Resources | MN Rules 103 G.271 | Surface Water Appropriation Permit | 690172 | N/A | Appropriation of river water from Mississippi River for cooling at 630,000 gpm or 235 MGY |
| Minnesota Department of Natural Resources | MN Rules 103 G.271 | Groundwater Appropriation Permit | 690171 | N/A | Wells 256120 (Installation #121) & 256121 (Installation #122), Appropriate groundwater for Plant operations |
| Minnesota Department of Natural Resources | MN Rules 103 G.271 | Groundwater Appropriation Permit | 785153 | N/A | Well 611076, Appropriate groundwater for motor cooling and lubrication of pump seals for cooling towers |
| Minnesota Department of Natural Resources | MN Rules 103G.271 | Groundwater Appropriation Permit | 865114 | N/A | Well 402599, Appropriate groundwater for pump bearing lubrication at PINGP |
| Minnesota Department of Natural Resources | MN Rules 103 G.271 | Groundwater Appropriation Permit | 965042 | N/A | Well 256074, Appropriate groundwater for Training Center domestic use and lawn irrigation |
| MN Department of Transportation | Minnesota Statutes, section 221.0355 | Registration | UPR-211635-MN | 10/27/2008 | Hazardous materials shipments |

**TABLE 9.1-1**
**ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT PINGP OPERATIONS (CONTINUED)**

| Agency | Authority | Requirement | Number | Expiration Date | Activity Covered |
|---|---|---|---|---|---|
| | | **Federal and State Requirements** | | | |
| Minnesota Pollution Control Agency, Industrial Division | Clean Water Act (33 USC 1251 et seq.), MN Statutes Chapts. 115, 116, and Rules Chapts. 7001, 7050, and 7060, National Pollutant Discharge Elimination System | Permit | MN0004006 | 08/31/2010 | Industrial wastewater discharges to Mississippi River |
| Minnesota Pollution Control Agency | Clean Air Act (42 USC 7401 et seq), MN Statutes Chapts. 115 and 116, MN Rules Chapt. 7007 | Permit | 00000001-003 | 12/17/2004 (renewal application submitted) | Operation of air emission system for an electric utility power generation system |
| Minnesota Pollution Control Agency | Clean Air Act (42 USC 7401 et seq), MN Regulations Chapters 7007.1150 to 7007.1500 | Permit | 04900030-003 | 01/3/2012 | Operation of oil-fired boiler and diesel-fired engines for emergency power, pump cooling water, fire fighting system |
| Minnesota Pollution Control Agency | Clean Water Act (33 USC 1251 et seq.), MN Rules 7100.0030. | Permit | MPCA 51557 | No expiration | Above ground storage tank registration |
| Minnesota Pollution Control Agency | MN Rules Chapter 7045, Statute 116.07 | License | MND049537780 | 06/30/2008 | Hazardous Waste Generator License, Small Quantity |

**TABLE 9.1-1**
**ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT PINGP OPERATIONS (CONTINUED)**

| Agency | Authority | Requirement | Number | Expiration Date | Activity Covered |
|---|---|---|---|---|---|
| **Federal and State Requirements** | | | | | |
| South Carolina Department of Health and Environmental Control – Division of Waste Management | South Carolina Radioactive Waste Transportation and Disposal Act (Act No. 429) | Permit | 0051-22-08-X | 12/31/2008 | Transportation of radioactive waste into the State of South Carolina |
| State of Tennessee Department of Environment and Conservation Division of Radiological Health | Tennessee Department of Environment and Conservation Rule 1200-2-10.32 | Permit | T-MN003-L08 | 12/31/2008 | Transportation of radioactive waste into the State of Tennessee |
| State of Utah Department of Environmental Quality Division or Radiation Control | Utah Radiation Control Rules R313-26 | Permit | 0402 002 748 | 02/23/2008 (renewal application submitted) | Transportation of radioactive into the State of Utah |
| Wisconsin Department of Natural Resources | WI State Statutes 29.614, 169.25, 19.31, 169.34, and 169.35 | Scientific Collectors Permit | SCP-WCR-20-C-08 | 12/31/2008 | Collect fish and ichthyoplankton for radiological and biological monitoring. |
| U.S. Army Corps of Engineers | Section 10 of River and harbor Act of 1899 (33 U.S.C. 403) | General Permit | GP/LOP-98-MN | 02/18/2008 | Maintenance dredging and erosion control discharge canal |
| U.S. Army Corps of Engineers | 10 U.S.C. 2668 | License | DACW37-3-06-0071 | 9/30/2011 | Air quality monitoring station at Lock and Dam Number 3. |

**TABLE 9.1-1**
**ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT PINGP OPERATIONS (CONTINUED)**

| Agency | Authority | Requirement | Number | Expiration Date | Activity Covered |
|---|---|---|---|---|---|
| | | **Federal and State Requirements** | | | |
| U.S. Army Corps of Engineers | Section 10 of River and harbor Act of 1899 (33 U.S.C. 403) | Dredging Permit | GP-01-MN | 05/15/.2006 | Maintenance dredging in front of the River Intake Structure |
| U.S. Department of Transportation | 49 USC 5108, 49CFR Part 107, Subpart G | Registration | 062706 552 0090 | 6/30/2008 | Hazardous materials shipments |
| U.S. Fish and Wildlife Service | 16 USC 703-712, Regulation 50 CFR Part 13, 50 CFR 21.27 | Special Purpose Federal Fish and Wildlife Permit | MB074020-0 | 3/31/2009 | Retrieve, transport, and temporarily possess carcasses of migratory birds. Collect, stabilize, and transport sick/ injured migratory birds. |
| U.S. Nuclear Regulatory Commission | Atomic Energy Act (42 USC 2011, et seq.), 10 CFR 50.10 | License to operate nuclear plant | DPR-42<br>DPR-60 | 08/09/2013<br>10/29/2014 | Operation of PINGP Unit 1<br>Operation of PINGP Unit 2 |

## TABLE 9.1-2
## ENVIRONMENTAL AUTHORIZATIONS FOR PINGP LICENSE RENEWAL[a]

| Requirement | Agency | Authority | Remarks |
|---|---|---|---|
| License renewal | U.S. Nuclear Regulatory Commission | Atomic Energy Act (42 USC 2011 et seq.) | Environmental Report submitted in support of license renewal application |
| Consultation | U.S. Fish and Wildlife Service (FWS) | Endangered Species Act Section 7 (16 USC 1536) | Requires federal agency issuing a license to consult with the FWS (Attachment C) |
| Certification | Minnesota Pollution Control Agency, Industrial Division | Clean Water Act Section 401 (33 USC 1341) | State issuance of NPDES permit (Attachment B) constitutes 401 certification (Section 9.1.4) |
| Consultation | Minnesota Historical Society | National Historic Preservation Act Section 106 (16 USC 470f) | Requires federal agency issuing a license to consider cultural impacts and consult with SHPO. (Attachment D) |

[a] No renewal-related requirements identified for local or other agencies.

## 9.3 REFERENCES

NRC (U.S. Nuclear Regulatory Commission). 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants. Volume 1.* NUREG-1437. Washington, DC. May.

# ATTACHMENT A

## NRC NEPA ISSUES FOR LICENSE RENEWAL

## OF NUCLEAR POWER PLANTS

NMC has prepared this environmental report in accordance with the requirements of U.S. Nuclear Regulatory Commission (NRC) regulation 10 CFR 51.53. NRC included in the regulation a list of National Environmental Policy Act (NEPA) issues for license renewal of nuclear power plants. Table A-1 lists these 92 issues and identifies the section in which NMC addressed each applicable issue in this environmental report. For organization and clarity, NMC has assigned a number to each issue and uses the issue numbers throughout the environmental report.

# TABLE A-1
# PINGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a]

| | Issue | Category | Section of this Environmental Report | GEIS Cross Reference[b] (Section/Page) |
|---|---|---|---|---|
| | **Surface Water Quality, Hydrology, and Use (for all plants)** | | | |
| 1. | Impacts of refurbishment on surface water quality | 1 | 4.1 | 3.4.1/3-4 |
| 2. | Impacts of refurbishment on surface water use | 1 | 4.1 | 3.4.1/3-4 |
| 3. | Altered current patterns at intake and discharge structures | 1 | 4.1 | 4.2.1.2.1/4-5 |
| 4. | Altered salinity gradients | 1 | NA | Issue applies to a plant feature, discharge to saltwater, that PINGP does not have. |
| 5. | Altered thermal stratification of lakes | 1 | NA | Issue applies to a plant feature, discharge to a lake, that PINGP does not have. |
| 6. | Temperature effects on sediment transport capacity | 1 | 4.1 | 4.2.1.2.3/4-8 |
| 7. | Scouring caused by discharged cooling water | 1 | 4.1 | 4.2.1.2.3/4-6 |
| 8. | Eutrophication | 1 | 4.1 | 4.2.1.2.3/4-9 |
| 9. | Discharge of chlorine or other biocides | 1 | 4.1 | 4.2.1.2.4/4-10 |
| 10. | Discharge of sanitary wastes and minor chemical spills | 1 | 4.1 | 4.2.1.2.4/4-10 |
| 11. | Discharge of other metals in waste water | 1 | 4.1 | 4.2.1.2.4/4-10 |
| 12. | Water use conflicts (plants with once-through cooling systems) | 1 | 4.1 | 4.2.1.3/4-13 |
| 13. | Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow) | 2 | 4.2.1 | 4.2.1.3/4-13 |
| 14. | Refurbishment impacts to aquatic resources | 1 | 4.1 | 3.5/3-5 |
| 15. | Accumulation of contaminants in sediments or biota | 1 | 4.1 | 4.2.1.2.4/4-10 |
| 16. | Entrainment of phytoplankton and zooplankton | 1 | 4.1 | 4.2.2.1.1/4-15 |

## TABLE A-1
## PINGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a] (CONTINUED)

| Issue | Category | Section of this Environmental Report | GEIS Cross Reference[b] (Section/Page) |
|---|---|---|---|
| **Aquatic Ecology (for all plants)** | | | |
| 17. Cold shock | 1 | 4.1 | 4.2.2.1.5/4-18 |
| 18. Thermal plume barrier to migrating fish | 1 | 4.1 | 4.2.2.1.6/4-19 |
| 19. Distribution of aquatic organisms | 1 | 4.1 | 4.2.2.1.6/4-19 |
| 20. Premature emergence of aquatic insects | 1 | 4.1 | 4.2.2.1.7/4-20 |
| 21. Gas supersaturation (gas bubble disease) | 1 | 4.1 | 4.2.2.1.8/4-21 |
| 22. Low dissolved oxygen in the discharge | 1 | 4.1 | 4.2.2.1.9/4-23 |
| 23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses | 1 | 4.1 | 4.2.2.1.10/4-24 |
| 24. Stimulation of nuisance organisms (e.g., shipworms) | 1 | 4.1 | 4.2.2.1.11/4-25 |
| **Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)** | | | |
| 25. Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems | 2 | 4.3 | 4.2.2.1.2/4-16 |
| 26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems | 2 | 4.4 | 4.2.2.1.3/4-16 |
| 27. Heat shock for plants with once-through and cooling pond heat dissipation systems | 2 | 4.5 | 4.2.2.1.4/4-17 |
| **Aquatic Ecology (for plants with cooling-tower-based heat dissipation systems)** | | | |
| 28. Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems | 1 | 4.1 | 4.3.3/4-33 |
| 29. Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems | 1 | 4.1 | 4.3.3/4-33 |

## TABLE A-1
## PINGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a] (CONTINUED)

| Issue | Category | Section of this Environmental Report | GEIS Cross Reference[b] (Section/Page) |
|---|---|---|---|
| 30. Heat shock for plants with cooling-tower-based heat dissipation systems | 1 | 4.1 | 4.3.3/4-33 |
| **Ground-water Use and Quality** | | | |
| 31. Impacts of refurbishment on groundwater use and quality | 1 | 4.1 | 3.4.2/3-5 |
| 32. Groundwater use conflicts (potable and service water; plants that use < 100 gpm) | 1 | NA | Issue applies to a plant feature, groundwater use less than 100 gpm, that PINGP does not have. |
| 33. Groundwater use conflicts (potable, service water, and dewatering; plants that use > 100 gpm) | 2 | 4.2.3 | 4.8.1.1 |
| 34. Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river) | 2 | 4.2.2 | 4.8.1.3/4-117 |
| 35. Groundwater use conflicts (Ranney wells) | 2 | NA | Issue applies to a feature, Ranney wells, that PINGP does not have. |
| 36. Groundwater quality degradation (Ranney wells) | 1 | NA | Issue applies to a feature, Ranney wells, that PINGP does not have. |
| 37. Groundwater quality degradation (saltwater intrusion) | 1 | NA | Issue applies to a feature, location in a coastal area, that PINGP does not have. |
| 38. Groundwater quality degradation (cooling ponds in salt marshes) | 1 | NA | Issue applies to a feature, cooling ponds, that PINGP does not have. |
| 39. Groundwater quality degradation (cooling ponds at inland sites) | 2 | NA | Issue applies to a feature, cooling ponds at inland sites, that PINGP does not have. |
| **Terrestrial Resources** | | | |
| 40. Refurbishment impacts to terrestrial resources | 2 | 4.6 | 3.6/3-6 |
| 41. Cooling tower impacts on crops and ornamental vegetation | 1 | 4.1 | 4.3.4/4-34 |
| 42. Cooling tower impacts on native plants | 1 | 4.1 | 4.3.5.1./4-42 |

# TABLE A-1
# PINGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a] (CONTINUED)

| Issue | Category | Section of this Environmental Report | GEIS Cross Reference[b] (Section/Page) |
|---|---|---|---|
| 43. Bird collisions with cooling towers | 1 | 4.1 | 4.3.5.2/4-45 |
| 44. Cooling pond impacts on terrestrial resources | 1 | NA | Issue applies to a feature, cooling ponds, that PINGP does not have. |
| 45. Power line right-of-way management (cutting and herbicide application) | 1 | 4.1 | 4.5.6.1/4-71 |
| 46. Bird collisions with power lines | 1 | 4.1 | 4.5.6.2/4-74 |
| 47. Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock) | 1 | 4.1 | 4.5.6.3/4-77 |
| 48. Floodplains and wetlands on power line right-of-way | 1 | 4.1 | 4.5.7/4-81 |
| **Threatened or Endangered Species (for all plants)** | | | |
| 49. Threatened or endangered species | 2 | 4.7 | 4.1/4-1 |
| **Air Quality** | | | |
| 50. Air quality during refurbishment (non-attainment and maintenance areas) | 2 | 4.8 | 3.3/3-2 |
| 51. Air quality effects of transmission lines | 1 | 4.1 | 4.5.2/4-62 |
| **Land Use** | | | |
| 52. Onsite land use | 1 | 4.1 | 3.2/3-1 |
| 53. Power line right-of-way land use impacts | 1 | 4.1 | 4.5.3/4-62 |
| **Human Health** | | | |
| 54. Radiation exposures to the public during refurbishment | 1 | 4.1 | 3.8.1/3-27 |
| 55. Occupational radiation exposures during refurbishment | 1 | 4.1 | 3.8.2/3-27 |
| 56. Microbiological organisms (occupational health) | 1 | 4.1 | 4.3.6/4-48 |

## TABLE A-1
## PINGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a] (CONTINUED)

| Issue | Category | Section of this Environmental Report | GEIS Cross Reference[b] (Section/Page) |
|---|---|---|---|
| 57. Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river) | 2 | 4.9 | 4.3.6/4-48 |
| 58. Noise | 1 | 4.1 | 4.3.7/4-49 |
| 59. Electromagnetic fields, acute effects (electric shock) | 2 | 4.10 | 4.5.4.1/4-66 |
| 60. Electromagnetic fields, chronic effects | NA | 4.1 | NA – Not applicable. The categorization and impact finding definitions do not apply to this issue. |
| 61. Radiation exposures to public (license renewal term) | 1 | 4.1 | 4.6.2/4-87 |
| 62. Occupational radiation exposures (license renewal term) | 1 | 4.1 | 4.6.3/4-95 |
| **Socioeconomics** | | | |
| 63. Housing impacts | 2 | 4.11 | 3.7.2/3-10 (refurbishment)<br>4.7.1/4-101 (renewal term) |
| 64. Public services: public safety, social services, and tourism and recreation | 1 | 4.1 | Refurbishment<br>3.7.4/3-14 (public services)<br>3.7.4.3/3-18 (safety)<br>3.7.4.4/3-19 (social)<br>3.7.4.6/3-20 (tour, rec)<br>Renewal Term<br>4.7.3/4-104 (public services)<br>4.7.3.3/4-106 (safety)<br>4.7.3.4/4-107 (social)<br>4.7.3.6/4-107 (tour, rec) |
| 65. Public services: public utilities | 2 | 4.12 | 3.7.4.5/3-19 (refurbishment)<br>4.7.3.5/4-107 (renewal term) |
| 66. Public services: education (refurbishment) | 2 | 4.13 | 3.7.4.1/3-15 |
| 67. Public services: education (license renewal term) | 1 | 4.1 | 4.7.3.1/4-106 |
| 68. Offsite land use (refurbishment) | 2 | 4.14 | 3.7.5/3-20 |
| 69. Offsite land use (license renewal term) | 2 | 4.14 | 4.7.4/4-107 |

## TABLE A-1
## PINGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a] (CONTINUED)

| Issue | Category | Section of this Environmental Report | GEIS Cross Reference[b] (Section/Page) |
|---|---|---|---|
| 70. Public services: transportation | 2 | 4.15 | 3.7.4.2/3-17 (refurbishment)<br>4.7.3.2/4-106 (renewal term) |
| 71. Historic and archaeological resources | 2 | 4.16 | 3.7.7/3-23 (refurbishment)<br>4.7.7/4-114 (renewal term) |
| 72. Aesthetic impacts (refurbishment) | 1 | 4.1 | 3.7.8/3-24 |
| 73. Aesthetic impacts (license renewal term) | 1 | 4.1 | 4.7.6/4-111 |
| 74. Aesthetic impacts of transmission lines (license renewal term) | 1 | 4.1 | 4.5.8/4-83 |
| **Postulated Accidents** | | | |
| 75. Design basis accidents | 1 | 4.1 | 5.3.2/5-11 (design basis)<br>5.5.1/5-114 (summary) |
| 76. Severe accidents | 2 | 4.17 | 5.3.3/5-12 (probablististic analysis)<br>5.3.3.2/5-19 (air dose)<br>5.3.3.3/5-49 (water)<br>5.3.3.4/5-65 (groundwater)<br>5.3.3.5/5-96 (economic)<br>5.4/5-106 (mitigation)<br>5.5.2/5-114 (summary) |
| **Uranium Fuel Cycle and Waste Management** | | | |
| 77. Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste) | 1 | 4.1 | 6.2/6-8 |
| 78. Offsite radiological impacts (collective effects) | 1 | 4.1 | Not in GEIS. |
| 79. Offsite radiological impacts (spent fuel and high-level waste disposal) | 1 | 4.1 | Not in GEIS. |
| 80. Nonradiological impacts of the uranium fuel cycle | 1 | 4.1 | 6.2.2.6/6-20 (land use)<br>6.2.2.7/6-20 (water use)<br>6.2.2.8/6-21 (fossil fuel)<br>6.2.2.9/6-21 (chemical) |
| 81. Low-level waste storage and disposal | 1 | 4.1 | 6.4.2/6-36 (low-level definition)<br>6.4.3/6-37 (low-level volume)<br>6.4.4/6-48 (renewal effects) |
| 82. Mixed waste storage and disposal | 1 | 4.1 | 6.4.5/6-63 |

## TABLE A-1
## PINGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a] (CONTINUED)

| Issue | Category | Section of this Environmental Report | GEIS Cross Reference[b] (Section/Page) |
|---|---|---|---|
| 83. Onsite spent fuel | 1 | 4.1 | 6.4.6/6-70 |
| 84. Nonradiological waste | 1 | 4.1 | 6.5/6-86 |
| 85. Transportation | 1 | 4.1 | 6.3/6-31, as revised by Addendum 1, August 1999. |
| **Decommissioning** | | | |
| 86. Radiation doses (decommissioning) | 1 | 4.1 | 7.3.1/7-15 |
| 87. Waste management (decommissioning) | 1 | 4.1 | 7.3.2/7-19 (impacts)<br>7.4/7-25 (conclusions) |
| 88. Air quality (decommissioning) | 1 | 4.1 | 7.3.3/7-21 (air)<br>7.4/7-25 (conclusion) |
| 89. Water quality (decommissioning) | 1 | 4.1 | 7.3.4/7-21 (water)<br>7.4/7-25 (conclusion) |
| 90. Ecological resources (decommissioning) | 1 | 4.1 | 7.3.5/7-21 (ecological)<br>7.4/7-25 (conclusion) |
| 91. Socioeconomic impacts (decommissioning) | 1 | 4.1 | 7.3.7/7-24 (socioeconomic)<br>7.4/7-25 (conclusion) |
| **Environmental Justice** | | | |
| 92. Environmental justice | NA | 2.5.3 | NA – Not applicable. The categorization and impact finding definitions do not apply to this issue. |

a Source: 10 CFR 51, Subpart A, Appendix A, Table B-1. (Issue numbers added to facilitate discussion.)
b Source: Generic Environmental Impact Statement for License Renewal of Nuclear Plants (NUREG-1437).
NEPA = National Environmental Policy Act.

# ATTACHMENT B

# NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

# STATE DISPOSAL PERMIT

Minnesota Pollution Control Agency

**CERTIFIED MAIL NO: 7004 2510 0000 2117 5535**
**RETURN RECEIPT REQUESTED**

Mr. Patrick Flowers
Manager, Water Quality Solid Waste
Northern States Power d/b/a Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401-1993

RE: Major Modification National Pollutant Discharge Elimination System/State Disposal System Permit No. MN 0004006
Xcel Prairie Island Nuclear Generating Plant
Welch, Minnesota

Dear Mr. Flowers:

Enclosed is a copy of the reissued final modified National Pollutant Discharge Elimination System (NPDES)/State Disposal System (SDS) permit for the Prairie Island Nuclear Generating Plant. This permit supersedes an earlier NPDES permit that was issued on September 23, 2005 and modified on January 26, 2006. All written comments received during the public notic period were considered.

It is the responsibility of the Permittee to maintain compliance with all of the terms and conditions of this permit. Please carefully review the entire permit.

We would like to draw your attention to the following:

Limits and Monitoring Requirements:
An additional requirement to monitor and report the total calendar month flow at surface discharge station SD 001 during the months of April, May, and June has been added. The previous permit required that this value be reported only for the months July through March. The modified permit requires year round monitoring and reporting for total calendar month flow at SD 001.

Dredged Material Management Requirements:
The modified permit includes requirements related to the storage, treatment, disposal and/or reuse of dredged material generated at Prairie Island Nuclear Generating Plant. The modified permit does not authorize or regulate the dredging activity itself. Prior to conducting dredging

520 Lafayette Rd. N.; Saint Paul, MN 55155-4194; (651) 296-6300 (Voice); (651) 282-5332 (TTY); www.pca.state.mn.us
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Mr. Patrick Flowers
Page 2

activities in the bed of public waters the Xcel Energy is required to contact the Minnesota Department of Natural Resources, the U.S. Army Corps of Engineers, the appropriate Soil and water Conservation District, county and/or local unit of government.

If you have any questions regarding any of the terms and conditions of the permit, please contact Katrina Kessler of our staff at 651-296-7376.

Sincerely,

Jeff Stollenwerk
Supervisor
Land and Water Quality Permits Section
Industrial Division

KK:lmg

Enclosures: Final Permit

cc: Jim Bodensteiner, Xcel Energy, Minneapolis (w/enclosures)
Brent Kuhl, Xcel Energy, Minneapolis (w/enclosures)
Jeanne Tobias, Xcel Energy, Prairie Island Plant (w/enclosures)
George Azevedo, Environmental Protection Agency, Chicago (w/enclosure)

Page 1
Permit MN0004006

**STATE OF MINNESOTA**
**Minnesota Pollution Control Agency**

**Industrial Division**

**National Pollutant Discharge Elimination System (NPDES) and State Disposal System (SDS) Permit MN0004006**

**PERMITTEE: Northern States Power Company d/b/a Xcel Energy**

**FACILITY NAME: Prairie Island Nuclear Generating Plant**

**RECEIVING WATERS: Mississippi River**

**CITY/TOWNSHIP: Welch** **COUNTY: Goodhue**

**MODIFICATION DATE: 6/30/2006** **EXPIRATION DATE: August 31, 2010**

The state of Minnesota, on behalf of its citizens through the Minnesota Pollution Control Agency (MPCA), authorizes the Permittee to discharge from this facility to the receiving waters named above, in accordance with the requirements of this permit.

The goal of this permit is to protect water quality according to Minnesota and U.S. statutes and rules, including Minn. Stat. chs. 115 and 116, Minn. R. chs. 7001, 7050 and 7060, and the U.S. Clean Water Act.

This permit is effective on the modification date identified above, and supersedes the previous permit that was issued for this facility on September 23, 2005, and modified on January 26, 2006.

This permit expires at midnight on the expiration date identified above.

*Signature:* ______________________________

Michael (Mike) J. Tibbetts, Manager *For* The Minnesota Pollution Control Agency
Land and Water Quality Permits Section
Industrial Division

If you have questions on this permit, including the specific permit requirements, permit reporting or permit compliance status, please contact:

**Minnesota Pollution Control Agency**
**Industrial Division**
**520 Lafayette Road North**
**St. Paul, MN 55155-4194**
**Telephone: (651) 296-7376**
**Fax: (651) 296-8717**
**Telephone Device for Deaf (TTY): (651) 282-5332**

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**Required Submittals**

**316(b) Required Submittals*:**

**Source water physical data required by 316(b) Phase II ............October 28, 2006**
**Cooling water intake structure data...............................................October 28, 2006**
**Cooling water system data..................................................October 28, 2006**
**Proposal for Information Collection .....................................October 28, 2006**
**Comprehensive Demonstration Study.........................................October 28, 2006**
**Results of IM &E Study...........................................................October 28, 2006**
**Design Construction Technology Plant......................................October 28, 2006**
**Technology Installation and Operation Plan ..........................October 28, 2006**
**Verification Monitoring Plan.........................................................October 28, 2006**

***The Permittee has tentatively selected Compliance Alternative (2) of 40 CFR 125.94 (a) to meet the impingement and entrainment reduction requirements. Alternative (2) requires that the Permittee demonstrate that existing design and construction technologies, operational measures, and/or restoration measures meet the impingement mortality and entrainment performance standards.***

**Other Submittals:**

**Storm water pollution prevention plan...........180 days after permit issuance**
**DMRs ......................................................21 days after the end of each calendar month following permit issuance**
**Application of permit reissuance ..................180 days before permit expiration**

**Permitted Facility Description**

This facility is a two unit nuclear fueled electric-generating plant. Both units use a pressurized water reactor system design with a maximum Nuclear Regulatory Commission (NRC) licensed power level of 1650 megawatts thermal per unit, which is equivalent to a combined maximum generating capacity of approximately 1100 megawatts electric for the facility. The treatment and disposal systems at the plant consist of a chemical treatment system, a reverse osmosis system, a radioactive waste (radwaste) treatment system, an intake screening system, and cooling towers. Water is withdrawn from wells for plant process uses, and from the river for condenser/circulating water system and cooling water systems. The condenser/circulating water system provides high volume cooling water flow for the turbine-condenser steam cycle whenever a unit is operating and also allows for excess heat rejection when a nuclear unit is at thermal power with the generator off-line. The cooling water system supplies other plant equipment, such as pumps, motors, and heat exchangers and is normally operated at all times.

The plant discharges condenser/circulating water and cooling water to the Mississippi River via the condenser/circulating water system discharge canal through surface discharge SD 001. During the winter months, a portion of the warm water from the discharge canal is returned to the intake screenhouse via a de-icing line to prevent ice build-up on the bar racks and traveling screens. The plant discharges steam generator blowdown through surface discharge SD 002. Radwaste treatment system effluent is discharged through surface discharge SD 003. The reverse osmosis (RO) system effluent is discharged through surface discharge SD 004. The unit 1 and unit 2 turbine building sumps, which are comprised of noncontact cooling water, condensate traps and drains, roof and floor drains, unit 1 and 2 condensate blowdown and the heating system blowdown, are discharged through surface discharges SD 005 and SD 006. Miscellaneous plant floor drains are discharged through surface discharge SD 010. All of the above surface discharges (SD) are ultimately discharged to the river via the circulating water system discharge canal, SD 001.

The plant intake screen backwash is discharged via SD 012. The fish return system which collects impinged fish, aquatic organisms, and debris off the vertical traveling screens is also discharged via SD 012. SD 012 discharges directly to the river.

The plant has two internal waste streams, the Unit 1 and Unit 2 cooling water systems. These systems are treated routinely with bromine and/or chlorine to control biofouling organisms and, when being treated, are designated as waste streams WS 001 and WS 002. Bromine and/or chlorine residuals are limited in accordance with this permit. Since WS 001 and WS 002 are comprised of cooling water system flow(s) at the time of treatment, these internal waste streams are also discharged to the river via the circulating water system at SD 001.

The plant also has an on land treatment and disposal system, typically referred to as the "land-lock drainage system." The land-lock drainage system is used for periodic disposal and treatment of turbine building sump discharges when the total suspended solids and oil and grease residual of the sump water is such that it exceeds applicable discharge limitations. The system consists of an approximately 500 ft long, 10 ft wide drainage trench which allows for treatment/filtration of collected water through a semi-permeable clay liner system. Reconstructed in 1998, the drainage trench does not discharge to surface waters, and accumulated water either evaporates or seeps away. Turbine building sump discharges to the land-lock drainage system are primarily composed of river water/sediment and solids.

The plant uses a number of chemical additives for various purposes within the plant systems and piping and may discharge residual concentrations of these additives via the surface discharges. The concentrations of any additives used that may contribute to a discharge have been reviewed and approved by the MPCA (reference NPDES Limits Matrix dated November 1, 2004) and are restricted accordingly. Any new chemical additive usage or increase in dosages used requires approval by the MPCA in accordance with Chapter 7 of this permit.

The plant is limited in the amount of heat it may discharge to the river. The thermal limitations regulating the plant cooling water discharge are described in Chapter 5 part 2 Applicable Effluent Limitations – Thermal Limitations. The plant's heat discharge or thermal load to the river is limited by mixed river temperature immediately below Lock and Dam No. 3, downstream of the plant. Cooling tower operation is sometimes required to meet the thermal limitations. To determine the ambient river water temperature, assess the plant's thermal input, and assure compliance with applicable thermal limitations, temperature monitoring is conducted at SD 001 (condenser/circulating water and cooling water discharge canal outfall), at the plant intake (SW 002), at the main river channel (SW 003-upstream river point), at a point(s) in Sturgeon Lake (SW 004-upstream river point), and immediately downstream of Lock and Dam No. 3 by three separate temperature probes (SW 001).

The plant is also regulated by the amount of river water that may be used for condenser and equipment cooling. The design of the various plant cooling systems does not allow for direct measurement or river intake flow but does allow for calculation of discharge flow SD 001 based on sluice gate positions and canal water elevation. River water withdrawal rates are controlled indirectly by imposing limitations on discharge flow at SD 001, which approximates intake flow. The discharge flows are limited from April 15 through June 30 in order to minimize the impingement of fish and fish larvae, as stated in Chapter 1, Part 5.1. The plant must operate the intake screening system throughout the year as required in Chapter 5, Parts 4.1 and 4.2 to assure impinged fish are returned to the river via the fish return system. In addition, during the period April 1 through August 31, the plant is required to operate the intake vertical traveling screens using the fine mesh screen material in order to minimize entrainment of larval fish, fish eggs, and other aquatic organisms.

Sanitary wastewater generated at the plant is treated using the plant's septic system or trucked to Red Wing WWTP or Prairie Island Community Water Treatment Plant.

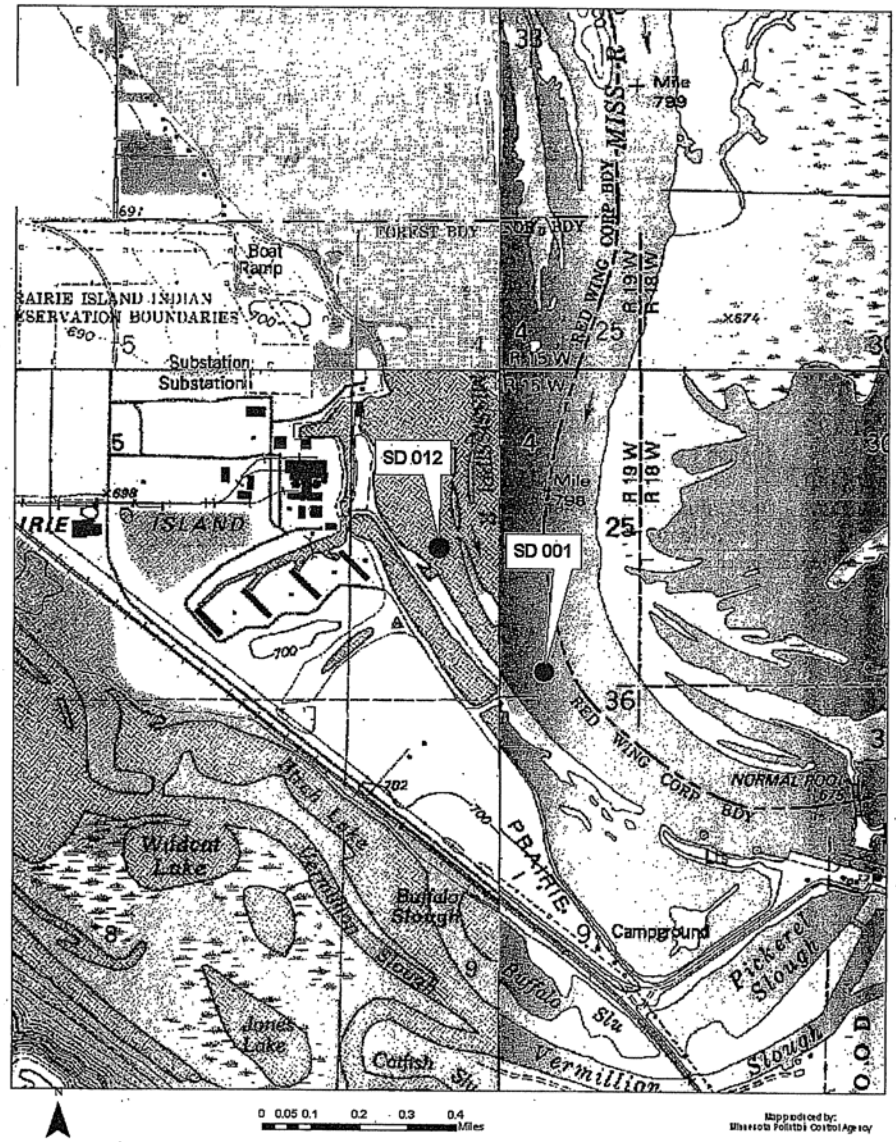
The surface discharge (SD) and internal waste stream (WS) discharges from the plant are described in the following table, with approximate flows in million gallons per day (MGD):

| DISCHARGE | WASTEWATER SYSTEM | MAXIMUM FLOW | AVERAGE FLOW |
|---|---|---|---|
| SD 001 | Condenser/Circulating Water and Cooling Water | 864 | 503 |
| SD 002 | Steam Generator Blowdown | 0.576 | 0.012 |
| SD 003 | Radioactive Waste Effluent | 0.230 | 0.002 |
| SD 004 | Reverse Osmosis Effluent | 0.244 [1] | 0.051 [1] |
| SD 005 | Unit 1 Turbine Building Sump | 0.360 | 0.030 |
| SD 006 | Unit 2 Turbine Building Sump | 0.360 | 0.030 |
| SD 010 | Miscellaneous Plant Floor Drains | 0.015 | 0.001 |
| SD 012 | Intake Screen Backwash and Fish Return | 3.2 | 2.0 |
| WS 001<br>WS 002 | Combined Unit 1 and Unit 2 Cooling Water (when subject to oxidation) | 69 | 25 |

Note: [1] Flows are based on available data for 3 months of system operation in 2005

The location of the facility and the selected monitoring stations is shown on the map below.

**Topographic Map of Permitted Facility**



Permit Modified: June 30, 2006
Permit Expires: August 31, 2010

**Xcel - Prairie Island Nuclear Generatin**
**Limits and Monitoring Requirements**

Page 7
Permit #: MN0004006

The Permittee shall comply with the limits and monitoring requirements as specified below.

SD 001: Condenser Circ Water & Cooling Water Sys (Applicable only during discharge)

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Chlorine Rate | Monitor Only | kg/day | Daily Maximum | Jan-Dec | Calculation | 1 x Day | 2 |
| Flow | Monitor Only | MG | Calendar Month Total | Jan-Dec | Measurement | 1 x Day | 1 |
| Flow | Monitor Only | mgd | Daily Average | Jul-Mar | Measurement | 1 x Day | 1 |
| Flow | 97 | mgd | Daily Average | Apr | Measurement | 1 x Day | 13 |
| Flow | 194 | mgd | Daily Average Intervention | Apr | Measurement | 1 x Day | 12 |
| Flow | 194 | mgd | Daily Average Intervention | May | Measurement | 1 x Day | 4 |
| Flow | 259 | mgd | Daily Average | Jun | Measurement | 1 x Day | 15 |
| Flow | 517.5 | mgd | Daily Average Intervention | Jun | Measurement | 1 x Day | 14 |
| Oxidants, Total Residual (Bromine), Continuous | 0.001 | mg/L | Daily Maximum | Jan-Dec | Calculation | 1 x Day | |
| Oxidants, Total Residual (Bromine), Intermittent | 0.05 | mg/L | Instantaneous Maximum | Jan-Dec | Grab | 1 x Day | |
| Oxidants, Total Residual (Chlorine), Continuous | 0.04 | mg/L | Daily Maximum | Jan-Dec | Calculation | 1 x Day | |
| Oxidants, Total Residual (Chlorine), Intermittent | 0.2 | mg/L | Instantaneous Maximum | Jan-Dec | Grab | 1 x Day | |
| pH | 9.0 | SU | Calendar Month Maximum | Jan-Dec | Grab | 1 x Week | 17 |
| pH | 6.0 | SU | Calendar Month Minimum | Jan-Dec | Grab | 1 x Week | 17 |
| Plant Capacity Factor, Percent of Capacity | Monitor Only | % | Calendar Month Average | Jan-Dec | Measurement | 1 x Day | |
| Temperature, Water | Monitor Only | Deg F | Single Value | Jan-Dec | Measurement, Continuous | 1 x Day | 7 |

SD 002: Steam Generator Blowdown Discharge

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Flow | Monitor Only | mgd | Calendar Month Average | Jan-Dec | Estimate | 1 x Month | |
| Flow | Monitor Only | MG | Calendar Month Total | Jan-Dec | Estimate | 1 x Month | |
| Solids, Total Suspended (TSS) | 65.3 | kg/day | Calendar Quarter Average | Jan-Dec | Grab | 1 x Quarter | |
| Solids, Total Suspended (TSS) | 30 | mg/L | Calendar Quarter Average | Jan-Dec | Grab | 1 x Quarter | |
| Solids, Total Suspended (TSS) | 217.0 | kg/day | Daily Maximum | Jan-Dec | Grab | 1 x Quarter | |
| Solids, Total Suspended (TSS) | 100 | mg/L | Daily Maximum | Jan-Dec | Grab | 1 x Quarter | |

Permit Modified: June 30, 2006
Permit Expires: August 31, 2010

**Xcel - Prairie Island Nuclear Generating**
**Limits and Monitoring Requirements**

Page 8
Permit #: MN0004006

The Permittee shall comply with the limits and monitoring requirements as specified below.

SD 003: Radwaste Treatment Effluent

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Flow | Monitor Only | mgd | Calendar Month Average | Jan-Dec | Estimate | 1 x Month | |
| Flow | Monitor Only | MG | Calendar Month Total | Jan-Dec | Estimate | 1 x Month | |
| Solids, Total Suspended (TSS) | 26.0 | kg/day | Calendar Quarter Average | Jan-Dec | Grab | 1 x Quarter | |
| Solids, Total Suspended (TSS) | 30 | mg/L | Calendar Quarter Average | Jan-Dec | Grab | 1 x Quarter | |
| Solids, Total Suspended (TSS) | 86.9 | kg/day | Daily Maximum | Jan-Dec | Grab | 1 x Quarter | |
| Solids, Total Suspended (TSS) | 100 | mg/L | Daily Maximum | Jan-Dec | Grab | 1 x Quarter | |

SD 004: Reverse Osmosis Effluent

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Flow | Monitor Only | mgd | Calendar Month Average | Jan-Dec | Estimate | 1 x Month | |
| Flow | Monitor Only | MG | Calendar Month Total | Jan-Dec | Estimate | 1 x Month | |

SD 005: Unit 1 Turbine Bldg Sump Dschg

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Flow | Monitor Only | mgd | Calendar Month Average | Jan-Dec | Estimate | 1 x Month | |
| Flow | Monitor Only | MG | Calendar Month Total | Jan-Dec | Estimate | 1 x Month | |
| Oil & Grease, Total Recoverable (Hexane Extraction) | 10 | mg/L | Calendar Month Average | Jan-Dec | Grab | 1 x Month | |
| Oil & Grease, Total Recoverable (Hexane Extraction) | 15 | mg/L | Daily Maximum | Jan-Dec | Grab | 1 x Month | |
| Solids, Total Suspended (TSS) | 30 | mg/L | Calendar Month Average | Jan-Dec | Grab | 1 x Month | 16 |
| Solids, Total Suspended (TSS) | 100 | mg/L | Daily Maximum | Jan-Dec | Grab | 1 x Month | 16 |

SD 006: Unit 2 Turbine Bldg Sump Dschg

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Flow | Monitor Only | mgd | Calendar Month Average | Jan-Dec | Estimate | 1 x Month | |
| Flow | Monitor Only | MG | Calendar Month Total | Jan-Dec | Estimate | 1 x Month | |
| Oil & Grease, Total Recoverable (Hexane Extraction) | 10 | mg/L | Calendar Month Average | Jan-Dec | Grab | 1 x Month | |
| Oil & Grease, Total Recoverable (Hexane Extraction) | 15 | mg/L | Daily Maximum | Jan-Dec | Grab | 1 x Month | |
| Solids, Total Suspended (TSS) | 30 | mg/L | Calendar Month Average | Jan-Dec | Grab | 1 x Month | 16 |

Permit Modified: June 30, 2006
Permit Expires: August 31, 2010

**Xcel - Prairie Island Nuclear Generating**
**Limits and Monitoring Requirements**

Page 9
Permit #: MN0004006

The Permittee shall comply with the limits and monitoring requirements as specified below.

SD 006: Unit 2 Turbine Bldg Sump Dschg

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Solids, Total Suspended (TSS) | 100 | mg/L | Daily Maximum | Jan-Dec | Grab | 1 x Month | 16 |

SD 010: Misc Plant Floor Drains Discharge

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Flow | Monitor Only | mgd | Calendar Quarter Average | Jan-Dec | Estimate | 1 x Quarter | |
| Flow | Monitor Only | MG | Calendar Quarter Total | Jan-Dec | Estimate | 1 x Quarter | |
| Oil & Grease, Total Recoverable (Hexane Extraction) | 10 | mg/L | Calendar Quarter Average | Jan-Dec | Grab | 1 x Quarter | |
| Oil & Grease, Total Recoverable (Hexane Extraction) | 15 | mg/L | Daily Maximum | Jan-Dec | Grab | 1 x Quarter | |
| Solids, Total Suspended (TSS) | 30 | mg/L | Calendar Quarter Average | Jan-Dec | Grab | 1 x Quarter | 16 |
| Solids, Total Suspended (TSS) | 100 | mg/L | Daily Maximum | Jan-Dec | Grab | 1 x Quarter | 16 |

SD 012: Intake Screen Backwash + Fish Retn

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Flow | Monitor Only | mgd | Calendar Month Average | Jan-Dec | Estimate | 1 x Month | |
| Flow | Monitor Only | MG | Calendar Month Total | Jan-Dec | Estimate | 1 x Month | 3 |

SW 001: Mississippi River Below Lock & Dam #3

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Temperature Difference Between Sample & Reference Point | 5 | Deg F | Monthly Average of Daily Maximum | Apr-Oct | Measurement, Continuous | 1 x Day | 9 |
| Temperature, Water | 86 | Deg F | Daily Average | Jan-Dec | Measurement, Continuous | 1 x Day | 8 |
| Temperature, Water | 43 | Deg F | Daily Average Intervention | Nov-Mar | Measurement, Continuous | 1 x Day | 5 |
| Temperature, Water | 43 | Deg F | Daily Average Intervention | Apr-Oct | Measurement, Continuous | 1 x Day | 10 |

SW 002: Plant Intake Channel

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Temperature, Water | Monitor Only | Deg F | Single Value | Jan-Dec | Measurement, Continuous | 1 x Day | 8 |

Permit Modified: June 30, 2006
Permit Expires: August 31, 2010

**Xcel - Prairie Island Nuclear Generating**
**Limits and Monitoring Requirements**

Page 10
Permit #: MN0004006

The Permittee shall comply with the limits and monitoring requirements as specified below.

SW 003: Main River Channel Upstream Pt.

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Temperature, Water | Monitor Only | Deg F | Single Value | Jan-Dec | Measurement, Continuous | 1 x Day | 8 |

SW 004: Sturgeon Lake - Upstream Pt.

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Temperature, Water | Monitor Only | Deg F | Single Value | Jan-Dec | Measurement, Continuous | 1 x Day | 8 |

WS 001: Unit 1Cooling Water Discharge

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Flow | Monitor Only | mgd | Calendar Month Average | Jan-Dec | Measurement, Continuous | 1 x Day | 6 |
| Flow | Monitor Only | MG | Calendar Month Total | Jan-Dec | Measurement, Continuous | 1 x Day | 6 |
| Oxidants, Total Residual | 2.0 | mg/L | Daily Maximum | Jan-Dec | Grab | 1 x Day | 11 |

WS 002: Unit 2 Cooling Water Discharge

| Parameter | Limit | Units | Limit Type | Effective Period | Sample Type | Frequency | Notes |
|---|---|---|---|---|---|---|---|
| Flow | Monitor Only | mgd | Calendar Month Average | Jan-Dec | Measurement, Continuous | 1 x Day | 6 |
| Flow | Monitor Only | MG | Calendar Month Total | Jan-Dec | Measurement, Continuous | 1 x Day | 6 |
| Oxidants, Total Residual | 2.0 | mg/L | Daily Maximum | Jan-Dec | Grab | 1 x Day | 11 |

Permit Modified: June 30, 2006
Permit Expires: August 31, 2010

**Xcel - Prairie Island Nuclear Generating**
**Limits and Monitoring Requirements**

Page 11
Permit #: MN0004006

The Permittee shall comply with the limits and monitoring requirements as specified below.

Notes:
1 -- Determined using flow curve and sluice gate position, see Chapter 9, Part 1.28.
2 -- During intermittent treatment, the discharge of total residual oxidants shall be limited to a total of 2 hours per 24 hour period. The Permittee shall monitor the amount and time of oxidant application and shall report it monthly.
3 -- Large debris collected at the trash racks shall be disposed of so as to prevent it from entering waters of the state
4 -- May exceed this flow limit if needed to keep from exceeding 85 degree F condenser inlet temperature operating limit provided that flow is minimized and cooling towers are operating to the maximum extent possible.
5 -- Once the temperature in the receiving water falls below 43 degrees F for five consecutive days the discharge shall not raise the temperature of the receiving water above 43 degrees for an extended period of time. If the temperature in the river is greater than 43 degrees F for two consecutive days the Permittee shall notify the MPCA. This limits applies until the ambient river temperature increases to 43 degrees F or above for 5 consecutive days or until April 1, whichever occurs first. The Permittee shall submit the daily maximum, daily average, and daily minimum temperature collected at each of the three monitoring probes located on the dividing piers at Lock and Dam No. 3 with the monthly DMR.
6 -- See Chapter 3 for data collection and reporting.
7 -- See Thermal Limitations in Chapter 5.
8 -- See applicable sections in Chapter 2 and 5 for thermal limitations and data collection requirements.
9 -- Starting April 1 the discharge shall not raise the temperature of the receiving water greater than 5 degrees F above the ambient water temperature based on the monthly averages of maximum daily temperatures at the three monitoring probes (reference point) located on the piers dividing Lock and Dam No. 3. This limit applies until such a point when the daily average temperature of the receiving water is less than 43 degrees F for 5 consecutive days.
10 -- Starting April 1 the discharge shall not raise the temperature of the receiving water greater than 5 degrees F above the ambient water temperature. This limit applies until such a point when the daily average temperature of the receiving water is less than 43 degrees F for 5 consecutive days. The Permittee shall submit the daily maximum, daily average, and daily minimum temperature for each of the three monitoring probes located on the dividing piers at Lock and Dam No. 3 with the monthly DMR.
11 -- The Permittee shall monitor SD 001 for total residual oxidant and be subject to the limitations as described in the Limits and Monitoring requirements for SD 001.
12 -- This limit applies from April 15 -30 when the flow in the receiving water is greater than or equal to 15, 000 cfs. May exceed this flow limit if needed to keep from exceeding the 85 degree F condenser inlet temperature operating limit provided that flow is minimized and cooling towers are operating to maximum extent possible.
13 -- This limit applies from April 15 -30 when the flow in the receiving water is less than 15, 000 cfs. May exceed this flow limit if needed to keep from exceeding the 85 degree F condenser inlet temperature operating limit provided that flow is minimized and cooling towers are operating to maximum extent possible.
14 -- This limit applies from June 16 - 30. May exceed this flow limit if needed to keep from exceeding 85 degree F condenser inlet temperature operating limit provided that flow is minimized and cooling towers are operating to the maximum extent possible.
15 -- This limits applies from June 1- 15. May exceed this flow limit if needed to keep from exceeding 85 degree F condenser inlet temperature operating limit provided that flow is minimized and cooling towers are operating to the maximum extent possible.
16 -- Where the background level of natural origin is reasonably definable and normally is higher than the specified limits for total suspended solids (average and maximum), the natural level may be used as the limit.
17 -- pH limit is not subject to averaging and shall be met at all times

## Chapter 1. Surface Discharge Stations

### 1. Sampling Location

1.1 Samples taken in compliance with monitoring requirements specified for surface discharge SD 001 shall be taken at a point representative of the discharge. Samples taken in compliance with monitoring requirements for outfalls 002, 003, 004, 010, and 012 shall be taken at a point representative of the discharge prior to mixing with other waste streams. Samples taken in compliance with monitoring requirements for outfalls 005 and 006 shall be taken at a point representative of the discharge prior to mixing with other waste streams, and samples shall be taken at each outfall.

### 2. Surface Discharges

2.1 Oil or other substances shall not be discharged in amounts that create a visible color film.

2.2 There shall be no discharge of floating solids or visible foam, except that which occurs naturally in the river, in other than trace amounts.

2.3 The Permittee shall install and maintain outlet protection measures at the discharge stations to prevent erosion if necessary.

### 3. Discharge Monitoring Reports

3.1 The Permittee shall submit monitoring results for discharges in accordance with the limits and monitoring requirements for this station. If no discharge occurred during the reporting period, the Permittee shall check the "No Discharge" box on the Discharge Monitoring Report (DMR).

### 4. Requirements for Specific Stations

4.1 SD 001: Submit a monthly DMR monthly by 21 days after the end of each calendar month following permit issuance.

4.2 SD 002: Submit a monthly DMR monthly by 21 days after the end of each calendar month following permit issuance.

4.3 SD 003: Submit a monthly DMR monthly by 21 days after the end of each calendar month following permit issuance.

4.4 SD 004: Submit a monthly DMR monthly by 21 days after the end of each calendar month following permit issuance.

4.5 SD 005: Submit a monthly DMR monthly by 21 days after the end of each calendar month following permit issuance.

4.6 SD 006: Submit a monthly DMR monthly by 21 days after the end of each calendar month following permit issuance.

4.7 SD 010: Submit a quarterly DMR quarterly by 21 days after the end of each calendar quarter following permit issuance.

4.8 SD 012: Submit a monthly DMR monthly by 21 days after the end of each calendar month following permit issuance.

### 5. Special Requirements

**Discharge Operations**

## Chapter 1. Surface Discharge Stations

### 5. Special Requirements

5.1 The plant cooling water discharge flows in million gallons per day (mgd) shall be limited as follows during the specified periods:

April 15 - 30: 194 mgd if the flow in the river is at or above 15,000 cfs
97 mgd if the flow in the river is below 15,000 cfs
May 1 - 31: 194 mgd
June 1 -15: 259 mgd
June 16-30: 517.5 mgd

5.2 The plant may discharge water at SD 001 at higher flow rates during the specified period if needed to prevent condenser inlet temperatures from exceeding 85 degree F provided that such higher flows are minimized to the extent practical, and all cooling towers are opearted to the maximum practical extent.

**316(b) Demonstration**
**Source Water Physical Data, Cooling Water Intake Structure Data, Cooling Water System Data**

5.3 The Permittee shall submit the source water physical data, cooling water intake structure data, and cooling water system data in accordance with the NPDES Final Regulations to Establish Requirements for Cooling Water Intake Structures at Phase II Existing Facilities, published July 9, 2004 in the Federal Register pursuant to 316(b) of the Clean Water Act, 40CFR Parts 9, 122, 123, 124, and 125.

The data shall be submitted by October 28, 2006.

**316(b) Proposal for Information Collection and Comprehensive Demonstration Study Requirements**

5.4 The Permittee has tentatively selected Compliance Alternative (2) of 40CFR 125.94 (a) to meet the impingement and entrainment reduction requirements. Alternative (2) requires that the Permittee demonstrate that existing design and construction technologies, operational measures, and/or restoration measures meet the impingement mortality and entrainment performance standards.

5.5 The Permittee shall submit a Proposal for Information Collection in accordance with the NPDES Final Regulations to Establish Requirements for Cooling Water Intake Structures at Phase II Existing Facilities by October 28, 2006.

5.6 The Permittee shall submit a comprehensive demonstration (CDS) study in accordance with 316(b) of the Clean Water Act, 40CFR Parts 9, 122, 123, 124, and 125. The 316(b) demonstration study elements, further described below, shall be implemented to assure that the location, design, construction, and capacity of the cooling water intake structure at the plant reflect the best technology available (BTA) for minimizing adverse environmental impact.

The 316(b) CDS shall demonstrate that the implementation and/or operation of technology and operational measures will reduce cooling water intake impingement mortality of all life stages of fish and shellfish by 80 to 95 and percent and will reduce entrainement by 60 to 90 percent from the baseline calculation, based on the 316(b) performance requirements for a freshwater river.

The Permittee shall submit the CDS by October 28, 2006.

**316(b) Demonstration Impingement Mortality and Entrainment (IM&E) Characterization Study (baseline development)**

## Chapter 1. Surface Discharge Stations

### 5. Special Requirements

5.7 The Permittee shall submit the results of an Implingement Mortality and Entrainment Characterization Study (IM&E Study). The study shall provide information to support the development of a calculation baseline for evaluating impingement mortality and entrainment consistent with the 316(b) rule. The Permittee may update the study upon request to, and approval by, the MPCA.

All field sampling shall be conducted under present normal plant operating conditions, screen rotation, and plant flows. Documentation shall be maintained of plant operations during sampling. All species impinged shall be identified, with weight and length measurements taken to the extent feasible. Data from historical studies may be included in the calculation of baseline impingement and entrainment if deemed relevant and appropriate.

8 The IM&E Study shall include the following in accordance with the 316(b) requirements:

a. Taxonomic identifications of all life stages of fish, shellfish, and any species protected under Federal, State, or Tribal Law (including threatened or endangered species) that are in the vicinity of the cooling water intake structure and are susceptible of impingement and entrainment.

b. A characterization of all life stages of fish, shellfish, and any species protected under Federal, State, and Tribal Law (including threatened or endangered species) identified pursuant to paragraph a. above, including a description of the abundance and temporal and spatial characteristics in the vicinity of the cooling water intake structure(s), based on sufficient data to characterize annual, seasonal, and diel variations in impingement mortality and entrainment (e.g. related to climate and weather differences, spawning, feeding, and water column migration). These may include historical data that are representative of the current operation and biological conditions at the site.

c. Documentation of the current impingement mortality of all life stages of fish, shellfish, and any species protected under Federal, State, or Tribal Law (including threatened or endangered species) identified pursuant to paragraph a. above and an estimate of impingement mortality and entrainment to be used as a baseline.

5.9 The Permittee shall submit the results of the IM&E study, by October 28, 2006. The submittal shall describe the calculated baseline for impingement mortality and entrainment and verify the calculated baseline based on the total acquired impingement and entrainment data.

**316(b) Demonstration**
**Design and Construction Technology Plan**

5.10 The Permittee shall submit a Design and Construction Technology Plan (DCT Plan) to the MPCA for review and approval. The DCT Plan shall describe the technologies and/or operational measures in place and/or selected to meet the impingement and entrainment performance requirements in the 316(b) Rule, 125.94.

5.11 The DCT Plan shall include the following information in accordance with 316(b) Rule requirements:

a. A narrative description of the design and operation of all design and construction technologies and/or operational measures (existing and proposed), including fish handling and return systems, that are in place or will be used to meet the requirements to reduce impingement mortality and entrainment of those species expected to be most susceptible, and information that demonstrates the efficacy of the technologies and/or operational measures for those species. A complete narative description is contained in the NPDES permit application.

b. Calculations of the reduction in impingement mortality and entrainment of all life stages of fish and shellfish that would be achieved by the technologies and/or operational measures selected, based on the IM&E study. The total reduction in mortality must be assessed against the calculation baseline.

c. Design and engineering drawings, and calculation results and descriptions, prepared by a qualified professional to support the descriptions required by paragraph a. above.

## Chapter 1. Surface Discharge Stations

### 5. Special Requirements

5.12 The DCT Plan shall be submitted to the MPCA for review and approval by October 28, 2006.

**316(b) Demonstration**
**Technology Installation and Operation Plan**

5.13 A Technology Installation and Operation Plan (TIO Plan) shall be submiited for MPCA review and approval. The TIO Plan shall includes the following in accordance with 316(b) Rule requirements:

a. A schedule for the maintenance of any new design and construction technologies. The technology installation shall be reasonably scheduled to ensure that impacts to energy reliability and supply are minimized.

b. List of operational and other parameters to be monitored, and the locations and frequency for monitoring.

c. List of activities to be undertaken to ensure to the degree practicable the efficacy of installed design and construction technologies and operational measures, and the schedule for implementation.

d. A schedule and methodology for assessing the efficacy of any installed design and construction technologies and operational measures in meeting applicable performance standards or site specific requirements, including an adaptive management plan for revising design and construction technologies, operational measures, operation and maintenance requirements, and/or monitoring requirements if the assessment indicates that applicable performance standards (impingement mortality and entriainment reductions) are not being met.

5.14 The TIO Plan shall be submitted to the MPCA for review and approval by October 28, 2006. The Permittee shall meet the terms of the TIO Plan in accordance with MPCA approval of the TIO Plan, including any revisions to the adaptive management plan component of the TIO Plan that may be necessary should applicable performance standards (impingement mortality and entrainment reductions) not be met.

**316(b) Demonstration**
**Verification Monitoring Plan**

5.15 The Permittee shall submit a Verification Monitoring Plan (VM Plan) to the MPCA for review and approval. The VM Plan shall describe the monitoring to be conducted over a period of 2 years designed to verify that the full-scale performance of the proposed or already implemented technologies and/or operational measures are successful in meeting the performance standards (applicable impingement mortality and entrainment reductions). The VM Plan shall provide the following:

a. Description of the frequency and duration of monitoring, the parameters to be monitored, and the basis for determining the parameters and the frequency and duration of monitoring. The parameters selected and duration and frequency of monitoring shall be consistent with any methodology for assessing success in meeting applicable performance standards in the TIO Plan. The method for assessment of success shall be specified including the averaging period for determining the percent reduction in impingement mortality.

b. A proposal on how naturally moribound fish and shellfish that enter the cooling water intake structure would be identified and taken into account in assessing success in meeting the performance standard.

c. A description of the information to be included in a subsequent biennial status report to the MPCA.

5.16 The VM Plan shall be submitted to the MPCA by October 28, 2006.

## Chapter 1. Surface Discharge Stations

### 5. Special Requirements

5.17 Verfication monitoring in accordance with the VM Plan shall be conducted for a period of 2 years to demonstrate whether the design and construction technology and/or operational measures meet the applicable performance standard (impingement mortality and entrainment reduction). A final report on verification monitoring shall be submitted to the MPCA within 120 days of completion of verification monitoring. The MPCA may approve a change to the plan at any time. The plan elements and procedures shall be followed as described in the latest approved version of the plan. The Permittee may make changes to the studies and plan upon request to, and approval by, the MPCA.

**316(b) Demonstration**
**Records**

5.18 The Permittee shall maintain records of significant data used to develop the IEM, TIO Plan, VM Plan; records regarding compliance with the requirements of the 316(b) Rule; and any compliance monitoring data for a period of at least 5 years from permit issuance.

**316(b) Demonstration**
**Biennial Status Report**

5.19 The Permittee shall submit a biennial status report beginning July 1, 2011 to the MPCA. The biennial status report shall summarize monitoring data and other information relevant to performance of the installed technology and/or operation measures. Other information shall include summaries of significant operation and maintenance records and summaries of adaptive management activities, or other information relevant to determining compliance with the facility's TIO Plan.

## Chapter 2. Surface Water Stations

### 1. Sampling Location

1.1 Temperature monitoring for SW Station 001 shall be taken by 3 separate probes located immediately downstream of Lock and Dam No. 3 on three piers dividing the four gated sections of the dam. Individual temperature (maximum, average, and minimum) data from each probe shall be collected and submitted. Compliance with the 5 degree F maximum allowable increase at SW 001 shall be based on the monthly average of the daily maximum temperature at the three probes. Temperature monitoring for SW Station 002 shall be taken at a point in the intake channel representative of river water temperature unaffected by the plant thermal discharge. Temperature monitoring for SW Station 003 shall be taken in the main river channel at a point unaffected by the plant thermal discharge. Temperature monitoring for SW Station 004 shall be taken in Sturgeon Lake at one or more points unaffected by the plant for thermal discharge.

### 2. Discharge Monitoring Reports

2.1 The Permittee shall submit monitoring results in accordance with the limits and monitoring requirements for this station. If flow conditions are such that no sample could be acquired, the Permittee shall check the "No Flow" box and note the conditions on the Discharge Monitoring Report (DMR).

2.2 For parameters required to be monitored continuously, portions of the monitoring data will occasionally be lost when equipment is out of service for repairs or while performing routine instrument calibrations and maintenance. In such cases, loss of one hour or less of data in a calendar day need not be reported unless the Permittee has reason to believe that resulting values reported on the DMR are not representative of actual conditions.

### 3. Requirements for Specific Stations

3.1 SW 001: Submit a monthly DMR monthly by 21 days after the end of each calendar month following permit issuance.

## Chapter 2. Surface Water Stations

### 3. Requirements for Specific Stations

3.2 SW 002: Submit a monthly DMR monthly by 21 days after the end of each calendar month following permit issuance.

3.3 SW 003: Submit a monthly DMR monthly by 21 days after the end of each calendar month following permit issuance.

3.4 SW 004: Submit a monthly DMR monthly by 21 days after the end of each calendar month following permit issuance.

### 4. Special Requirements

**Exceedance of Permit Thermal Limitations Under Energy Emergencies**

4.1 The thermal limitations of this permit may be exceeded for a limited period under extreme conditions of electrical energy emergencies. Exceedance of the thermal limitations may occur only during electrical energy emergencies. For purposes of this permit an "electrical energy emergency" is defined as the time period when Northern States Power Company's, d/b/a Xcel Energy (Permittee or Xcel Energy), generating system is in System Conditioning Operating Code Red, or when in System Code Orange (danger) if degradation to Code Red appears likely absent corrective action.

4.2 System Code Red (emergency) occurs when the energy supply is subject to, but not limited to, partial power interruptions, curtailment of energy supply to controlled customers and peak controlled customers, power interruption to commercial customers, and reduction of peak voltage. It represents a situation where all electrical reserves have been exhausted, the electrical grid is unstable, and electrical demand has exceeded electrical supply. Code Red is also commonly referred to as a "brown-out". A Code Red may also lead to interruption to retail customers and power interruption, commonly referred to as a rotating "black-out".

System Code Orange (danger) occurs when the entire electrical system is vulnerable to instability due a single failure, such as a potential transmission fault, loss of a generating unit, or other technical failure. It represents a situation where electric power demand is currently being met but utility equipment is being operated at or near maximum dependable capacity and remaining energy reserves are extremely low or non existent. Under Code Orange energy controlled customers and energy peak customers are being curtailed, external energy is unavailable, and loss of an Xcel electrical generating unit or external purchase would result in Xcel being unable to meet required NERC (North American Electric Reliability Council) operating requirements.

4.3 Thermal limitation exceedances may occur only under the following conditions:

1. Thermal limitation exceedances will only be considered under an electrical energy emergency. Xcel Energy shall base decisions regarding thermal limitation exceedances on engineering and operational measures necessary to maintain stable regional energy supplies and protect critical generation and transmission equipment. Xcel Energy shall take all reasonable corrective actions available to avoid thermal limitation exceedances.

2. Thermal limitation exceedances are allowable only after Xcel Energy has exhausted all other reasonable alternatives or determined them to be inadequate. These alternatives include, but are not limited to, use of all available Xcel Energy power generation including Xcel Energy oil burning facilities and reserves, energy purchases, demand side management measures, curtailment of non-essential auxiliary load, and public appeals for voluntary energy conservation measures. Energy costs, either incurred at Xcel Energy generating facilities or through energy purchased, shall not be a factor in exhausting these alternatives.

3. Xcel Energy shall restore operations to return to compliance with permit thermal limitations as soon as possible upon termination of the electrical energy emergency, that is, upon return to a stable system Code Orange (danger) or better system code. The duration of thermal limitation exceedances shall be minimized.

## Chapter 2. Surface Water Stations

### 4. Special Requirements

4.4

4. Xcel Energy shall limit the severity of thermal limitation exceedances to the extent possible. Xcel Energy shall maintain any existing cooling tower systems and other cooling systems used to remove heat from cooling water to be discharged, so that these cooling systems are completely available during energy emergencies.

5. Xcel Energy shall attempt to notify the MPCA in advance of its intent to exercise this provision to exceed the permit thermal limitations under an electrical energy emergency. If Xcel Energy is unable to provide advance notification, due to sudden problems caused by storms, unplanned loss of critical generation or transmission, or similar circumstances causing conditions to rapidly deteriorate, Xcel Energy shall notify MPCA staff as soon as possible after the initial response actions are completed. If the event occurs after normal business hours or a weekend Xcel Energy shall notify the State Duty Officer and provide follow up notification to MPCA the next business day.

6. Xcel Energy shall institute monitoring for any environmental impacts during exceedances of the thermal limitations. Specifically Xcel Energy shall institute periodic biological observations of the zone of influence of the thermal discharge on the receiving water and any plant discharge canal, to monitor for signs of dead or distressed fish and other aquatic life. Any dead or distressed fish observed shall be tabulated and recorded by Xcel Energy staff and reported within one day, or the next business day if on a weekend, to the MPCA and the Minnesota Department of Natural Resources (MDNR).
Xcel Energy shall submit a monitoring plan for biological observations during electrical energy emergencies, within 30 days after issuance of this permit.

4.5

7. Xcel Energy shall comply with the Minnesota Department of Natural Resources (MDNR) requirements concerning any costs or charges levied by the MDNR for fish or other aquatic organisms lost due to any thermal limitation exceedances.

8. Unless otherwise specified by the MPCA, during an electrical energy emergency Xcel Energy shall provide a daily summary of the status of plant operations, the nature and extent of any permit deviations or exceedances of the thermal limitations, any mitigating actions being taken, and any observed environmental impacts. The daily summaries shall be provided by telephone and e-mail message to the MPCA during business days. Daily summaries during the weekend shall be provided by e-mail message.

## Chapter 2. Surface Water Stations

### 4. Special Requirements

4.6

9. Xcel Energy shall provide a written summary of any thermal limitation exceedances pursuant to an electrical energy emergency within 30 days of termination of the energy emergency. The summary shall address at a minimum:

a. The specific cause of the electrical energy emergency and information describing the conditions leading to the energy emergency which may include, but are not limited to, weather conditions and power demands.

b. The system code that Xcel Energy was operating under and all steps that Xcel took to lower energy demand and/or increase energy output in order to prevent a thermal limitation exceedance. These steps include, but are not limited to, items such as operation of peaking and oil burning plants, internal load reduction measures, energy purchases, public appeals for voluntary energy reduction, implementation of curtailment of service to interruptible customers, power interruption to commercial customers, etc.

c. A statement confirming that the electrical energy emergency leading to exceedances of thermal limitations was unintentional and that there was no known, viable engineering alternative for deviation from the plantt s permitted thermal limitations. A similar statement confirming that the electrical energy emergency leading to exceedances of thermal limitations resulted from factors beyond Xcel Energy's control and did not result from operator error, improperly designed facilities, lack of preventative maintenance, or increases in production beyond the design capacity of the treatment facility (cooling equipment).

4.7

d. A written summary of the technical aspects of the facility that are involved with cooling and maintaining compliance with thermal limitations.

e. Information on any alternatives to a thermal limitation exceedance and impacts that would likely have occurred if power generation was reduced in order to avoid a thermal limitation exceedance. Such impacts may include public health and safety, public security issues, damage to generating plants, disruption of commercial and industrial processes, and related potential impacts.

f. If it is determined that the thermal limitation exceedance was the result of inadequate design, operations or maintenance, the actions Xcel Energy will take to avoid a future thermal limitation exceedance.

## Chapter 2. Surface Water Stations

### 4. Special Requirements

4.8 This provision is meant to provide for limited and infrequent short-term exceedances of the permit thermal limitations solely under extreme and relatively unique circumstances (such as an unusual heat wave). This provision does not preclude the MPCA from subsequently requiring Xcel Energy to resolve any recurring thermal limitation exceedances through installation of additional cooling equipment, or other measures to remove excess heat, in the event that thermal exceedances become relatively frequent or are the result of inadequate design under normal (non-emergency) conditions.

This provision does not preclude the MPCA from taking any enforcement action pursuant to thermal limitation exceedances if the above conditions are not followed.

## Chapter 3. Waste Stream Stations

### 1. Sampling Location

1.1 Samples for Station WS 001 and WS 002 shall be taken at each internal wastestream, units 1 and 2, cooling water discharge or at another point representative of the discharge prior to mixing with circulating water or any other waters.

1.2 The Permittee shall submit monitoring results for discharges in accordance with the limits and monitoring requirements for this station. If no discharge occurred during the reporting period, the Permittee shall check the "No Discharge" box on the Discharge Monitoring Report (DMR).

1.3 For parameters required to be monitored continuously, portions of the monitoring data will occasionally be lost when equipment is out of service for repairs or while performing routine instrument calibrations and maintenance. In such cases, loss of one hour or less of data in a calendar day need not be reported unless the Permittee has reason to believe that resulting values reported on the DMR are not representative of actual conditions.

### 2. Requirements for Specific Stations

2.1 WS 001: Submit a monthly DMR monthly by 21 days after the end of each calendar month following permit issuance.

2.2 WS 002: Submit a monthly DMR monthly by 21 days after the end of each calendar month following permit issuance.

### 3. Special Requirements

3.1 If the need arises to raise the halogen level above 2.0 mg/l for WS 001 and WS 002, units 1 and 2 plant cooling water, a calculation shall be performed using the actual condenser/circulating water and cooling water flow halogen demand determined at that time. This information shall be submitted with the other monitoring data required in the monthly DMR.

3.2 A calculation shall be performed using the actual cooling water flow rate, condenser/circulating water flow rate and the halogen demand of 0.5 mg/l. The calculation consists of the ratio of total cooling water flow rate to the condenser/circulating water flow rate multiplied by the highest measured cooling water halogen level, minus the condenser/circulating water demand (0.5 ppm). The value should be a negative value showing that all the halogen was used prior to discharge to the river

## Chapter 4. Industrial Process Wastewater

### 1. Prohibited Discharges

1.1 The Permittee shall prevent the routing of pollutants from the facility to a municipal wastewater treatment system in any manner unless authorized by the pretreatment standards of the MPCA and the municipal authority.

1.2 The Permittee shall not transport pollutants to a municipal wastewater treatment system that will interfere with the operation of the treatment system or cause pass-through violations of effluent limits or water quality standards.

1.3 This permit does not authorize the discharge of sewage, wash water, scrubber water, spills, oil, hazardous substances, or equipment/vehicle cleaning and maintenance wastewaters to ditches, wetlands or other surface waters of the state except as permitted in the NPDES permit, for site treatment systems.

### 2. Hydrotest Discharges

2.1 The Permittee shall notify the MPCA prior to discharging hydrostatic test waters. The Permittee shall provide information necessary to evaluate the potential impact of this discharge and to ensure compliance with this permit. This information shall include:

a. the proposed discharge dates;

b. the name and location of receiving waters, including city or township, county, and township/range location;

c. an evaluation of the impact of the discharge on the receiving waters in relation to the water quality standards;

d. a map identifying discharge location(s) and monitoring point(s);

e. the estimated average and maximum discharge rates;

f. the estimated total flow volume of discharge;

g. the water supply for the test water, with a copy of the appropriate Minnesota Department of Natural Resources (DNR) water appropriation permit;

h. water quality data for the water supply;

i. proposed treatment method(s) before discharge; and

j. methods to be used to prevent scouring and erosion due to the discharge.

2.2 The above notificaiton procedure does not apply to routine hydrostatic tests of plant equipment provided all of the following conditions are met:

a. The test is conducted using the equipment's normal process water.

b. The hydrostatic discharge is through the designated outfall for that equipment when in normal operation (as identified in this permit).

c. The water meets all applicable discharge criteria for that outfall, including volume and rate.

d. There are no residual chemicals or contaminants present of a type or at levels beyone those already reviewed and approved as acceptable by the MPCA staff for that outfall.

### 3. Polychlorinated Biphenyls (PCBs)

3.1 PCBs, including but not limited to those used in electrical transformers and capacitors, shall not be discharged or released to the environment.

## Chapter 4. Industrial Process Wastewater

### 4. Application for Permit Reissuance

4.1 The permit application shall include priority pollutant analytical data as part of the application for reissuance this permit. These analyses shall be done on individual samples taken during the two year period before the reissuance application is submitted.

## Chapter 5. Dredged Material Management

### 1. Authorization

1.1 This permit is intended to regulate the storage, disposal and/or reuse of dredged material.

1.2 This permit authorizes the Permittee to store, dispose, and/or reuse dredged material in accordance with the provisions of this permit.

1.3 This permit does not authorize or otherwise regulate dredging activity. However, dredging activity is subject to the water quality standards specified in Minnesota Rules chs. 7050 and 7060.

Initiation of dredge activities shall not commence until the Permittee has obtained all federal, state and/or local approvals that may be required for a particular project, including but not limited to state permits regulating activities in the bed of public waters as defined in Minn. Stat. sec. 105 from the Minnesota Department of Natural Resources (DNR), federal permits for dredged or fill material from the U.S. Army Corps of Engineers, and local permits from the appropriate Soil and Water Conservation District, county or local unit of government (LUG).

1.4 Compliance with the terms and conditions of this permit releases the Permittee from the requirement to obtain a separate permit for construction and/or industrial activities at the storage, disposal and/or reuse site that would otherwise require the Permittee to obtain a construction and/or industrial storm water permit in accordance with the Clean Water Act and Agency rules, except where the use or reuse of dredged material is occurring at a location separate from other activity covered by this permit.

### 2. Sampling and Analyses

2.1 Characterization of sediment from the proposed dredge site must be completed prior to the initiation of dredging activity. Results of sediment characterization must be compiled and submitted to the MPCA prior to the start of dredging. Characterization shall consist of at least a grain size analysis and, if applicable, baseline and additional sediment analysis per Tables 3 and 4 of Appendix 1.

2.2 Grain Size Analysis

The Permittee shall complete a sieve grain size analysis using ASTM Method C-136 for the gradation analysis and ASTM Method D-2487 for classification. The minimum number of samples required for the analysis shall be determined using table 1 in Appendix 1. If the sieve analysis obtained is greater than 95 percent sands then the material is acceptable for Tier 1 or 2 use and additional analytical sampling is not required.

2.3 Baseline Sediment Analysis

Dredged material not excluded from additional analysis (as determined by the grain size analysis), must be analyzed for the constituents listed in Table 2 of Appendix 1.

2.4 Additional Analysis

If it is established through a review of past activities at the site that there is a reasonable likelihood for a pollutant to be present in sediment at a dredge site, the dredged material must be analyzed for additional analyte(s) in accordance with Table 3 and Table 4 in Appendix 1.

## Chapter 5. Dredged Material Management

### 3. Rehandling, Off-Loading and Transportation of Dredged Material

3.1 Dredged materials shall be managed in a manner so as to minimize the amount of material returned by spillage, erosion or other discharge to waters of the state during rehandling, off-loading and/or transportation activities.

3.2 Areas for the rehandling and/or off-loading of dredged material shall be sloped away from surface water or otherwise controlled.

3.3 Dredged material hauled on federal, state, or local highways, roads, or streets must be hauled in such a way as to prevent dredged material from leaking, spilling, or otherwise being deposited in the right-of-way. Dredged material deposited on a public roadway must be immediately removed and properly disposed.

3.4 Tracked soil and/or dredged material shall be removed from impervious surfaces that do not drain back to the dredged material storage, disposal and/or reuse facility within 24 hours of discovery, and placed in the storage, disposal and/or reuse facility site.

### 4. Storage, Disposal and/or Reuse of Dredged Material

4.1 Authorization. Prior to the use of a new (different from already disclosed) site for the storage, disposal, and/or reuse of dredged material, the Permittee shall obtain written MPCA approval for such use.

4.2 General. Any site used for the storage, disposal and/or reuse of a dredged material shall be operated and maintained by the Permittee to control runoff, including stormwater, from the facility to prevent the exceedance of water quality standards specified in Minnesota Rules, chs. 7050 and 7060.

4.3 The Permittee may dispose of dredged material at a permitted solid waste landfill, through on-site disposal, or through reuse for a beneficial purpose, as follows:
a. Temporary storage and/or treatment of dredged material at the dredge project site. Temporary storage of dredged material is subject to the requirements of part 3.4 of this chapter.
b. Disposal of dredged material at the dredge project site. Disposal of dredged material is subject to parts 3.5 through 3.36 of this chapter.
c. Reuse of dredged material for beneficial purposes. Reuse of dredged material is subject to parts 3.37 through 3.39 of this chapter.

**A. Temporary Storage and/or Treatment of Dredged Material**

4.4 All of the following requirements apply to the temporary storage and/or treatment of dredged material:
a. Temporary storage shall not exceed 1 year. Storage or accumulation of dredged material for more than 1 year constitutes disposal, and is subject to the disposal facility requirements of parts 3.5 through 3.36 of this chapter.
b. Dredged materials shall be managed in a manner so as to minimize the amount of material returned by spillage, erosion or other discharge to waters of the state. Best management practices for the management of dredged materials are outlined in the MPCA fact sheet, "Best Management Practices for the Management of Dredged Material".
c. If dikes, berms or silt fences have been constructed to contain temporary stockpiles of dredged material, they shall not be removed until all material has been removed from the stockpile.

**B. Disposal of Dredged Material**

4.5 Notification. Notification of a new or existing dredge disposal facility shall be submitted for MPCA review and approval.

4.6 Disposal facilities shall be constructed/operated in accordance with local requirements, including the requirement to obtain a permit, license, or other governmental approval to initiate construction.

## Chapter 5. Dredged Material Management

### 4. Storage, Disposal and/or Reuse of Dredged Material

4.7 Initial Site Plan. An initial site plan shall be prepared and submitted for MPCA review and approval. The initial site plan shall consist of volume calculations for the final permitted capacity and a map of the facility. The map of the facility shall include the permitted boundaries, dimensions, site contours (at contour intervals of two feet or less), soil boring locations with surface elevations and present and planned pertinent features, including but not limited to roads, screening, buffer zone, fencing, gate, shelter and equipment buildings, and surface water diversion and drainage. The initial site plan must be signed by a land surveyor registered in Minnesota or a professional engineer registered in Minnesota.

4.8 Delineation and Identification of Permitted Waste Boundary. The perimeter or outer limit of a dredged material disposal facility shall be indicated by permanent posts or signage. In addition, a permanent sign, identifying the operation and showing the permit number of the site, shall be posted at the dredged material disposal facility.

**Site Selection and Use**

4.9 Locational Prohibitions. All of the following locational standards apply to any facility for the disposal of dredged material:
a. The disposal facility must be located entirely above the high water table.
b. The disposal facility must not be located within a shoreland or wild and scenic river land use district governed by Minn. R. chapters 6105 and 6120.
c. The disposal facility must not be located within a wetland, unless the Permittee has obtained all federal, state and/or local approvals that may be required for a particular project.
d. The disposal area shall not be located in an area which is unsuitable because of topography, geology, hydrology, or soils.

4.10 Separation Distances. A minimum separation distance of 50 feet must be maintained between the boundaries of the disposal facility and the site property line.

**Design Requirements**

4.11 The following design standards apply to a facility used for the disposal of dredged materials:
a. An earthen containment dike, or other MPCA approved embankment and/or other sediment control measure(s), shall be established around the perimeter of the dredged material disposal facility (permitted waste boundary).
b. Site preparation shall allow for orderly development of the site. Initial site preparations shall include clearing and grubbing, topsoil stripping and stockpiling, fill excavation, if appropriate, drainage control structures, and other design features necessary to construct and operate the facility.
c. Surface water runoff shall be diverted around dredged materials disposal facilities to prevent erosion, and protect the structural integrity of exterior embankments from failure.
d. Slopes and drainageways shall be designed to prevent erosion. Slopes longer than 200 feet shall be interrupted with drainageways.
e. Final slopes for the fill area shall be a minimum two percent and a maximum 20 percent, and shall be consistent with the planned ultimate use for the site.
g. Final cover shall consist of at least 18 inches of soil with the top 12 inches capable of sustaining vegetative growth.
h. For a system that will impound water (e.g. hydraulic dredging) with a constructed dike over 6 feet in height, or that impound more than 15 acre-feet of water, the system is subject to Minn. R. parts 6115.0300 through 6115.0520 [state Dam Safety Program]. Contact state Dam Safety Program staff at (651) 296-0521 for more information.

## Chapter 5. Dredged Material Management

### 4. Storage, Disposal and/or Reuse of Dredged Material

4.12 Site Stabilization. The Permittee shall stabilize the dredged material disposal facility before any disposal in the facility is allowed, as follows:

a. The exterior slope of all permanent dikes or berms shall be no steeper than 3 to 1 (horizontal to vertical). The exterior slopes of all permanent dikes or berms must be seeded and a soil fixative (e.g. mulch, blanket) applied within 72 hours of the completion of any grading work on the slopes.

b. If grading work is completed too late in the growing season to seed or plant the desired species, then the Permittee must propagate an annual cover crop that can be dormant seeded or planted and must apply a soil fixative to the site. At the very minimum, the Permittee must apply a soil fixative to the exterior slopes of all permanent dikes or berms prior to the first snowfall.

c. Silt fences, if used, must be properly installed. The silt fences shall be tall enough and installed at a sufficient distance from the base of the permanent dikes/berms or temporary stockpiles to create a reasonable secondary containment area.

4.13 Operational Plan. An Operational Plan of the site and immediately adjacent area shall be developed and implemented, and shall show progressive development of trench and/or area fills and any phase construction. The scale of the development plan shall not be greater than 200 feet per inch.

4.14 Facilities for the disposal of dredged material shall be designed by a professional engineer registered in the state of Minnesota, and in accordance with the criteria in parts 3.13 and 3.14 of this chapter. The Permittee shall construct the facility in accordance with these design plans and specifications under the direct supervision of a professional engineer registered in the state of Minnesota.

4.15 Certification Required. Prior to use of a facility for the disposal of dredged material under this part, the Permittee shall obtain and submit written certification from an engineer licensed in Minnesota stating that the disposal facility meets the requirements of parts 3.13 and 3.14 of this chapter, and has been constructed in accordance with the design plans and specifications.

**Site Management, Limitations, and Restrictions**

4.16 New or Expanded Facilities. All of the following requirements apply to the construction of new or expanded facilities used for the disposal of dredged material:

a. The Permittee shall plan for and implement construction practices that minimize erosion and maintain dike integrity.

b. Erosion control measures shall be established on all downgradient perimeters prior to the initiation of any upgradient land-disturbing construction activities.

c. Surface runoff must be directed around and away from the storage and/or disposal facility site, until the site is stabilized, usually by assuring that vegetative cover is well-established.

d. Sediment control practices shall be designed and implemented to minimize sediment from entering surface waters. The timing of the installation of sediment control practices may be adjusted to accommodate short-term activities such as equipment access. Any short-term activity must be completed as quickly as possible and the sediment control practices must be installed immediately after the activity is completed. However, sediment control practices must be installed before the next precipitation event even if the activity is not complete.

e. All erosion and sediment control measures shall remain in place until final stabilization has been established. Permanent cover or final stabilization methods are used to prevent erosion, such as the placement of rip rap, sodding, or permanent seeding or planting. Permanent seeding and planting must have a uniform perennial vegetation cover of at least 70 percent density to constitute final stabilization.

## Chapter 5. Dredged Material Management

### 4. Storage, Disposal and/or Reuse of Dredged Material

4.17 Management of Disposal Facilities. The following standards apply to a facility used for the disposal of dredged material:
a. Each fill phase shall be outlined with grade stakes, and staked for proper grading and filling.
b. All trenches or fill areas shall be staked with permanent markers.
c. A permanent benchmark shall be installed on-site and show its location on the facility as-built plan.
d. Run-on and run-off of stormwater shall be controlled. The owner or operator must implement management practices designed to control run-on and run-off of stormwater from the disposal facility.
e. Vegetative cover shall be established within 120 days of reaching the final permitted capacity of the dredged material disposal facility, or within 120 days of the inactivation or completion of a phase of the facility thereof.
f. If the disposal facility contains any particulate matter that may be subject to wind dispersion, the owner or operator shall cover or otherwise manage the dredged material to control wind dispersion.
g. Nuisance conditions resulting from the disposal of dredged material shall be controlled and managed by the facility owner or operator.
h. Cover slopes shall be surveyed and staked during placement.

**Inspection and Maintenance**

4.18 Periodic Site Inspections. The Permittee shall inspect the disposal facility to ensure integrity of the erosion control measures, system stability and dredged material containment. At a minimum, the facility shall be inspected:
a. prior to the initial placement of any dredged material in the facility; and,
b. within 24 hours of each significant storm event and/or the subsidence of flood events; or,
c. at least once per month if a and/or b, above, are not occurring.
Inspections may be less frequent once a project is complete assuming all material has been transported to an off-site permitted facility or reused in accordance with this permit and is vegetated.

4.19 Recordkeeping. The Permittee shall record the date of each inspection, any problem identified with the facility, and the action(s) taken to correct any identified problem. The Permittee shall keep these inspection records on site and available to MPCA staff upon request.

4.20 Nonfunctioning erosion and sediment control measures shall be repaired, replaced or supplemented with functioning erosion and/or sediment control measures within three days of discovery.

4.21 Dikes and berms constructed to contain hydraulically dredged material and the attendant liquid must be maintained free of all types of animal burrows. Animal burrows should be backfilled with compacted material within three days of discovery.

4.22 Where dredging and disposal have been suspended due to frozen ground conditions, the inspections and maintenance shall begin as soon as weather conditions warrant, or prior to resuming dredged material placement in the disposal facility, whichever occurs first.

**Sediment Removal and Disposal**

4.23 Dredged material shall be removed from disposal facilities in a manner so as to not damage the integrity and effectiveness of the containment structure or area.

4.24 Dredged material removed from a storage, disposal, and/or reuse facility shall be managed in accordance with this chapter.

4.25 Recordkeeping. The Permittee shall record the dates, the volume of dredged material removed from the disposal facility, and the method and location of the disposition (disposal or reuse) of such materials. This information shall be submitted with the annual 'Dredged Material Report', as specified in the 'Annual Report' part of this chapter.

**Closure and Post-Closure Requirements**

## Chapter 5. Dredged Material Management

### 4. Storage, Disposal and/or Reuse of Dredged Material

4.26 The Permittee must cease to dispose of dredged materials and immediately close the dredged material disposal facility when:
a. the Permittee declares the dredged material disposal facility closed;
b. all fill areas reach final permitted capacity;
c. an agency permit held by the facility expires, and renewal of the permit is not applied for, or is applied for and denied;
d. an agency permit for the facility is revoked; and/or,
e. an agency order to cease operations is issued.

4.27 Closure Plan. The Permittee shall prepare and submit a 'Closure Plan' for the final closure of a dredged material disposal facility for MPCA review and approval.

4.28 The 'Closure Plan' shall identify the steps needed to close the entire site at the end of its operating life. The closure plan shall include the following elements:
a. A description of how and when the entire facility will be closed. The description shall include the estimated year of closure and a schedule for completing each fill phase.
b. An estimate of the maximum quantity of dredged material in storage at any time during the life of the facility.
c. A cost estimate including an itemized breakdown for closure of each fill phase and the total cost associated with closure activities at dredged material disposal facilities.

4.29 A copy of the approved 'Closure Plan' and all revisions to the plan shall be kept at the facility until closure is completed and certified. At the time of closure, the agency will issue a closure document in accordance with Minn. R. part 7001.3055.

4.30 Amendment of Plan. The Permittee may amend the 'Closure Plan' (plan) any time during the life of the facility. The Permittee shall amend the plan whenever changes in the operating plan or facility design affect the closure procedures needed, and whenever the expected year of closure changes. Required amendments shall be completed within 60 days of any change or event that affects the closure plan.

4.31 Notification of Final Facility Closure. The Permittee shall notify the commissioner at least 90 days before final facility closure activities are to begin, except if the permit for the facility has been revoked.

4.32 Closure Performance Standard. The Permittee must close the dredged material disposal facility in a manner that eliminates, minimizes, or controls the escape of pollutants to ground water or surface waters, to soils, or to the atmosphere during the postclosure period.

4.33 Completion of Closure Activities. Within 30 days after receiving the last shipment of dredged material for disposal, the Permittee must begin the final closure activities outlined in the approved 'Closure Plan' for the dredged material disposal facility. Closure activities must be completed according to the approved 'Closure Plan'. The commissioner may approve a longer period if the owner or operator demonstrates that the closure activities will take longer due to adverse weather or other factors not in the control of the Permittee.

4.34 Closure Procedures.
a. Complete the appropriate activities outlined in the approved 'Closure Plan'.
b. Complete final closure activities consisting of submitting to the county recorder and the commissioner a detailed description of the waste types accepted at the facility and what the facility was used for, together with a survey plat of the site. The plat must be prepared and certified by a land surveyor registered in Minnesota. The landowner must record a notation on the deed to the property or on some other instrument normally examined during a title search, that will in perpetuity notify any potential purchaser of the property of any special conditions or limitations for use of the site, as set out in the 'Closure Plan' and closure document.

## Chapter 5. Dredged Material Management

### 4. Storage, Disposal and/or Reuse of Dredged Material

4.35 Certification of Closure. When final facility closure is completed, the Permittee shall submit to the commissioner certification by the Permittee and an engineer registered in Minnesota that the facility has been closed in accordance with this chapter.

The certification shall contain the following elements:
a. a completed and signed 'Site Closure Record';
b. documentation of closure, such as pictures, showing the construction techniques used during closure; and,
c. a copy of the notation carrying the recorder's seal which has been filed with the county recorder.

4.36 Post-Closure Care. After final closure, the Permittee shall comply with the following requirements:
a. restrict access to the facility by use of gates, fencing, or other means to prevent further disposal at the site, unless the site's final use allows access;
b. maintain the integrity and effectiveness of the final cover, including making repairs to the final cover system as necessary to correct the effects of settling, subsidence, gas and leachate migration, erosion, root penetration, burrowing animals, or other events;
c. prevent run-on and run-off from eroding or otherwise damaging the final cover;
d. protect and maintain surveyed benchmarks

**C. Beneficial Use or Re-Use of Dredged Material**

4.37 Prior to the use or reuse of a dredged material, the Permittee shall determine the appropriate "suitable reuse category" of the dredged material to be used or reused, as described below.

4.38 Suitable Reuse Categories. The suitable reuse category of a dredged material is based on the analyzed characteristics of the dredged material (sampled prior to dredging or in a spoil pile after dreding) and appropriately applied Soil Reference Values (SRVs), which are listed in Table 2 of Appendix 1 to this permit.

For the purposes of this permit, dredged material intended for the beneficial use or reuse is categorized into three tiers: Tier 1, Tier 2, and Tier 3. If the sieve analysis obtained by a #200 sieve is greater than 95 percent sands then the material is acceptable for Tier 1 or 2 use and additional analytical sampling is not required.

a. Tier 1 material is authorized to be used or reused at/on sites with a residential property use category. Tier 1 material is characterized by a contaminant level that is at or below all respective analyte concentrations listed in the Tier 1 SRV column for any contaminant that can be reasonably expected to be present in the dredged material.
b. Tier 2 material is authorized to be used or reused on/at sites with an industrial or recreational use category. Tier 2 material is characterized by a contaminant level that is at or below all respective analyte concentrations listed in the Tier 2 SRV column for any contaminant that can be reasonably expected to be present in the dredged material.
c. Tier 3 material is NOT authorized to be used or reused under this permit. Tier 3 material is characterized by a contaminant level that is greater than any respective analyte concentrations listed in the Tier 2 SRV column for any contaminant that can be reasonably expected to be present in the dredged material.

4.39 Storage Prior to Reuse. Storage of dredged material prior to reuse or use is subject to the temporary storage requirements of this chapter, or the disposal requirements of this chapter, as applicable.

## Chapter 5. Dredged Material Management

### 5. Annual Report

5.1 The annual 'Dredged Material Report' shall be on a form provided by the Commissioner, or another MPCA approved form, and shall include the following elements:
a. Dates of dredging;
b. Volume of material placed into storage or disposal facility;
c. Any incidents, such as spills, unauthorized discharge and/or other permit violations which may have occurred;
d. Water level records for the disposal facilities of hydraulic dredging projects;
e. Such information as the MPCA may reasonably require of the Permittee pursuant to Minn. R. 7001 and Minn. Stat. chap. 115 and 116 as amended;
f. For disposal facilities, the dates of 'Periodic Site Inspections' required by this chapter, and the status of erosion control measures at the disposal facility;
g. For disposal facilities, the dates, the volume of dredged material removed from the disposal facility, and the method and location of the disposition (disposal or reuse) of such materials.
h. For facilities that used or reused dredged material during the previous calendar year, the following information shall also be provided:
i. A written description of the use or reuse of the dredged material;
ii. A written determination of the use category and appropriate Soil Reference Values (SRVs); and,
iii. The results of an evaluation of the level of contaminants in the dredged material proposed for reuse for the respective SRVs.

### 6. Definitions

6.1 "Beach Nourishment" means the disposal of dredged material on the beaches or in the water waterward starting at or above the Ordinary High Water Level (OHWL) for the purpose of adding to, replenishing, or preventing the erosion of, beach material.

6.2 "Beneficial Re-use" means the re-use of dredged material, after the material has been dewatered, in projects such as, but not limited to: road base, building base or pad, etc.

6.3 "Carriage, or Conveyance, Water" means the water portion of a slurry of water and dredged material.

6.4 "Carriage Water Return Flow" means the carriage water which is returned to a receiving water after separation of the dredged material from the carriage water in a disposal, rehandling or treatment facility.

6.5 "Design capacity" means the total volume of compacted dredged materials, along with any topsoil, intermittent intermediate, and/or final cover, as calculated from final contour and cross-sectional plan sheets that define the areal and vertical extent of the fill area.

6.6 "Discharges of Dredged Material" means any addition of dredged material into waters of the state and includes discharges of water from dredged material disposal operations including beach nourishment, upland, or confined disposal which return to waters of state. Material resuspended during normal dredging operations is considered "de minimis" and is not a dredged material discharge.

6.7 "Disposal Facility" means a structure, site or area for the disposal of dredged material.

6.8 "Dredged Material" means any material removed from the bed of any waterway by dredging.

6.9 "Dredging" means any part of the process of the removal of material from the beds of waterways; transport of the material to a disposal, rehandling or treatment facility; treatment of the material; discharge of carriage or interstitial water; and disposal of the material.

6.10 "Erosion Control" means methods employed to prevent erosion. Examples include: soil stabilization practices, horizontal slope grading, temporary or permanent cover, and construction phasing. (look for SW definition)

6.11 "Final Stabilization" means that all soil disturbing activities at the site have been completed, and that a uniform perennial vegetative cover (a density of 70 percent cover for unpaved areas and areas not covered by permanent structures) has been established or equivalent permanent stabilization measures have been employed. Examples of vegetative cover practices can be found in Supplemental Specifications to the 1988 Standard Specifications for Construction (Minnesota Department of Transportation, 1991).

## Chapter 5. Dredged Material Management

### 6. Definitions

6.12 "Flood Event" means that the surface elevation of a waterbody has risen to a level that causes the inundation or submersion of areas normally above the Ordinary High Water Level.

6.13 "Impoundment" means a natural or artificial body of water or sludge confined by a dam, dike, floodgate, or other barrier.

6.14 "Interstitial, or Pore, Water" means water contained in the interstices or voids of soil or rock in the dredged material.

6.15 "Ordinary High-Water Level (OHWL)" means the boundary of waterbasins, watercourses, public waters, and public waters wetlands, and shall be an elevation delineating the highest water level which has been maintained for a sufficient period of time to leave evidence upon the landscape, commonly that point where the natural vegetation Cs from predominantly aquatic to predominantly terrestrial. For watercourses, the ordinary high water level is the elevation of the top of the bank of the channel. For reservoirs and flowages, the ordinary high water level is the operating elevation of the normal summer pool. (Minn. Stat. chap. 103G.005 Subd. 14 and MN Rule 6120.2500 Subp. 11.)

6.16 "Rehandling Facility" means a temporary storage site or facility used during the transportation of dredged material to a treatment or disposal facility.

6.17 "Significant Storm Event" means a storm event that is greater than 1.0 inches in magnitude and that occurs at least 72 hours from the previously measurable (greater than 1.0 inch rainfall) storm event. The 72-hour storm event interval may be waived where:

a. the preceding measurable storm event did not result in a measurable discharge from the facility; or,

b. the Permittee documents that less than a 72-hour interval is representative for local storm events during the season when sampling is being conducted.

6.18 "Stabilized" means staked sod, riprap, wood fiber blanket, or other material that prevents erosion from occurring has covered the exposed ground surface. Grass seed is not stabilization.

6.19 "Storage Facility" means a structure, site or area for the holding of dredged material for more than 48 hours in quantities equal to or greater than ten cubic yards. Storage for more than 1 year constitutes disposal.

6.20 "Unconfined Disposal" means the deposition of dredged material, in water, on the bed of a waterway.

6.21 "Upland Disposal" means the disposal of dredged materials landward from the ordinary high-water level of a waterway or waterbody.

## Chapter 6. Steam Electric

### 1. Authorization

1.1 The Permittee is authorized to discharge condenser/circulating water and noncontact cooling water in accordance with and in compliance with the effluent limitations, restrictions, and conditions contained elsewhere in this permit.

1.2 The Permittee holds a Minnesota Department of Natural Resources Permit 80-5081, which requires the facility to maintain the wetland (duck pond) adjacent to the discharge canal.

1.3 The Permittee is not prohibited from a discharge of condenser/circulating water and cooling water for use as a de-icing agent at the intake structure should the need arise.

### 2. Applicable Effluent Limitations - Thermal Limitation

2.1 The thermal waste streams shall not impact the safety and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on the Mississippi River.

## Chapter 6. Steam Electric

### 2. Applicable Effluent Limitations - Thermal Limitation

2.2 In accordance with the Federal Water Pollution Control Act, this permit may be re-opened to insert a more restrictive thermal limit or the requirement to conduct a 316(a) study if it has been shown that the thermal component(s) of the surface water discharges affect the safety and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on the Mississippi River.

2.3 For the purposes of this permit, the fall trigger point is defined as the point at which the daily average upstream ambient river temperature falls below 43 degrees F for five consecutive days.

During the period April 1 through the fall thermal point the Permittee shall operate the cooling towers and associated equipment, to the extent necessary, in such a way that the cooling water discharge satisfies the following conditions:

1) Does not raise the temperature of the receiving water immediately below Lock and Dam No. 3 by more than 5 degrees F above ambient based on upstream monitoring data and the monthly averages of maximum daily temperatures at the three monitoring probes located on the piers dividing the four gated sections of the dam.

2) In no case shall it exceed a daily average temperature of 86 degrees F.

3) If the daily average ambient river temperature reaches 78 degrees F for two consecutive days, the Permittee shall operate all cooling towers to the maximum extent practicable. For single unit operations, this requirement is satisfied by operation of two of the four cooling towers.

2.4 During the effective period (beginning on the fall trigger point and ending March 31), or earlier as described below, plant thermal discharges shall be limited by ambient river temperature as follows:

Once the daily average ambient river temperature falls below 43 degrees F for five consecutive days, the Permittee shall not raise the temperature of the receiving water immediately below Lock and Dam No. 3 (SW 001) above 43 degree F for an extended period of time. While operating under this restriction, if the daily average temperature in the receiving water measured at SW 001 (measured using three probes on the piers dividing the four gated sections of the dam) equals or exceeds 43 degrees F for two consecutive days, the Permittee shall notify the Commissioner and the Minnesota Department of Natural Resources. Following such notification the Commission may require the Permittee to operate the cooling towers or take alternative action as necessary until such time that the 43 degree F criteria can be consistently met.

2.5 The spring trigger point is defined as the point in time that the daily average ambient river temperature increases to 43 degrees F or above for five consecutive days, or April 1, whichever occurs first.

The Permittee shall operate in the above manner (Section 2.4) throughout the winter and into spring until the spring trigger point. Once the spring 43 degree F daily average ambient river temperature trigger or the April 1 date trigger has been reached, plant thermal limits default back to the requirements of Section 2.3 until the following fall thermal trigger point. If the temperature trigger results in a partial month of operation under Section 2.3 conditions/requirements, compliance with the Delta T of 5 degrees F shall be based on the monthly average of the maximum daily ambient temperatures on days after the trigger is reached.

From April 1, or earlier as described above, through the fall thermal trigger point the requirements of Section 2.3 apply.

2.6 Abrupt temperature changes in the discharge due to changes in cooling tower operational modes or generator unit tripouts shall be minimized to the maximum extent practical to reduce the potential for thermal shock in the receiving water (Mississippi River). The Permittee shall be responsible for fish kills in the receiving water (Mississippi River) and the recirculating water system due to thermal shock and chemical treatments.

2.7 The ambient river water temperature shall be defined as the temperature of the river at a point unaffected by the plant or any other thermal discharge and shall be representative of the main river channel temperature and Sturgeon Lake outlet temperature.

## Chapter 6. Steam Electric

### 2. Applicable Effluent Limitations - Thermal Limitation

2.8 The Permittee shall monitor the temperature of the receiving water immediately below Lock and Dam No. 3 continuously (using three probes on the piers dividing the four gated sections of the gates), and this data shall be reported along with the monthly discharge monitoring reports. The Permittee shall maintain the site temperature monitoring system for outfall SD 001.

2.9 The Permittee shall conduct temperature monitoring for stations including the combined effluent from the condenser/circulating water system and cooling water system (SD001), upstream locations Strugeon Lake 1, Sturgeon Lake 2, Diamond Bluff (main channel), the screenhouse inlet temperature (intake channel), and the three separate temperature probes located at Lock and Dam No. 3 (on the piers dividing the four gated sections of the dam). The minimum, maximum, and average temperatures shall be recorded daily at these stations and reported with the monthly discharge monitoring reports.

The Permittee shall maintain the site temperature monitoring system encompassing ambient river temperature, Lock and Dam No. 3, intake, and outfall SD 001. Eliminations or reductions in portions of the system may be allowed as the information is compiled. The Permittee may evaluate the reliability and/or representativeness of the monitoring system and its various stations. Any relocations in the system, and reductions or eliminations of monitoring requirements are subject o MPCA review and approval.

2.10 If monitoring equipment for Sturgeon Lake 1, Sturgeon Lake 2, or Diamond Bluff (main channel) is out of service, then intake temperature monitoring may be utilized as the back up for ambient river water temperature determination. If either Sturgeon Lake 1 or Surgeon Lake 2 is out of service, the remaining station(s) may be utilized as the backup for Sturgeon Lake temperature inputs to determine ambient river water temperature. The Sturgeon Lake 1 and Sturgeon Lake 2 temperature monitoring equipment may be removed from service in the fall after the daily average ambient river temperature is below 43 degrees F for two consecutive days. The Sturgeon Lake 1 and Sturgeon Lake 2 temperature monitoring equipment shall be reinstalled in the spring, once the potential for damage from ice and floating debris is minimal. It shall be installed prior to, or as soon after April 1 as practical.

### 3. Chlorination

3.1 Chlorine/bromine may be used only in the cooling water system, except chlorine or bromine may be used in the condenser/circulating cooling water system periodically to treat for parasitic amoeba or zebra mussels provided the circulating cooling water is dechlorinated prior to discharge.

The Permittee shall monitor the amount and time of bromine/chlorine application and shall report it monthly on the DMRs

3.2 During intermittent bromination the discharge of total residual oxidant (bromine/chlorine used) at SD 001, shall be limited to a total of 2 hours per 24 hour period and to an instantaneous maximum concentration of 0.05 mg/l. During continuous chlorination the discharge of total residual oxidant shall be limited to an instantaneous maximum concentration of 0.2 mg/l. The Permittee shall also monitor the amount and time of chlorine and or bromine application and shall report it monthly along with the other monitoring reports.

At times, plant configuration can result in shutdown of a unit's cooling water pump (WS 001 or WS 002) for a short period of time with continuous chlorine/bromine injection in progress. During this time, chlorine/bromine injection would continue via the normal injection path but could back flow through the idle cooling water pump suction and be drawn into the condenser/circulating water system. Any chlorine/bromine would be subsequently discharged to SD 001, the normal discharge for both the cooling water and condenser/circulating water systems. In this off-normal plant configuration, chlorine/bromine injection may continue at the normal rate provided SD 001 discharge limits are not exceeded. Any plant operation in this off-normal configuration shall be documented on the monthly DMR.

## Chapter 6. Steam Electric

### 3. Chlorination

3.3 The discharge of total residual oxidants at SD001, bromine/chlorine used, shall be limited during intermittent bromination/chlorination to a total or two hours per 24-hour period from the facility. The Permittee shall also monitor the amount and time of chlorine and/or bromine application and shall report it monthly along with the other monitoring reports.

### 4. Intake Screens

4.1 The Permittee may operate with up to 3/8 inch mesh screens during the period September 1 through March 31. During the April 1 through August 31 period, the Permittee shall use the 0.5 mm fine mesh screens, or alternate minimum larger sized screens upon approval by the MPCA.

4.2 The intake screening system shall be maintained to provide for continuous fine mesh screen operation during the sensitive period April 1 through August 31 in order to minimize mortality of fish and other organisms. Operation shall include maintaining design screen wash pressures and operation of all intake screens to minimize fish impingement/entrainment and mortality. Maintenance of the intake screen system shall be scheduled and completed during the less sensitive impingement/entrainment period of September 1 through March 31. This restriction applies only to routine planned maintenance that 1) requires the intake screening system (or a portion of the system) to be taken out of service, and that 2) could reasonably be scheduled and completed outside of the time period of concern (March 31-September 1) without adversely affecting personnel safety or equipment reliability.

The Permittee shall minimize the amount of time that intake screenhouse emergency bypass gates are open. The emergency bypass gates may be opened when necessary to meet Nuclear Regulatory Commission reactor safety and testing requirements or to allow for urgently required maintenance or repairs. If the bypass gates are open for more than 24 hours in a calendar month the dates and circumstances shall be reported in the next DMR.

4.3 Water used to rinse the intake screens shall be free of chlorine and chemical additives.

4.4 Large debris collected at the trash racks shall be disposed of so as to prevent it from entering waters of the state.

4.5 The Permittee shall be responsible for fish kills in the receiving water and the recirculating water system due to thermal shock and chemical treatments.

4.6 The permit may be reopened and modified based on ecological monitoring and studies by the Minnesota Department of Natural Resources, the Wisconsin Department of Natural Resources, Northern States Power, and the MPCA.

4.7 The Permittee shall submit a monitoring plan to maintain ecological monitoring consistent with the Annual Environmental reports to the Commissioner for approval within 45 days of the effective date of this permit. The monitoring plan shall include the impingement study discussed in part 4.6 above. The Commissioner shall consult with the Minnesota Department of Natural Resources in review and approval of the ecological monitoring plan.

4.8 The Permittee shall submit an Annual Environmental report to the Commissioner by July 1 of each year summarizing the previous years' data collection.

4.9 The Commissioner shall consult with the Minnesota Department of Natural Resources in review and approval of the ecological monitoring submittals described in section 4.7 and 4.8 of this chapter.

## Chapter 7. Stormwater

### 1. Authorization

1.1 This chapter authorizes the Permittee to discharge storm water associated with industrial activity in accordance with the terms and conditions of this chapter.

## Chapter 7. Stormwater

### 2. Stormwater Pollution Prevention Plan

2.1 The Permittee shall submit a copy of the Storm Water Pollution Prevention Plan (SWPPP) to the MPCA 180 days after the permit is issued. Subsequent revisions to the SWPPP during the permit terms can be retained at the facility.

2.2 The Stormwater Pollution Prevention Plan shall include a description of appropriate Best Management Practices for protection of surface and ground water quality at the facility, and a schedule for implementing the practices. The Plan shall also include the procedures to be followed by designated staff employed by the Permittee to implement the plan.

2.3 The Permittee shall comply with its Stormwater Pollution Prevention Plan.

2.4 The Permittee shall develop and implement a Storm Water Pollution Prevention Plan to address the specific conditions at the industrial facility. The goal of the Plan is to eliminate or minimize contact of storm water with significant materials that should be treated before it is discharged.

### 3. Temporary Protection and Permanent Cover

3.1 The Permittee shall provide and maintain temporary protection or permanent cover for the exposed areas at the facility.

3.2 Temporary protection methods are used to prevent erosion on a short-term basis, such as the placement of mulching straw, wood fiber blankets, wood chips, erosion control netting, or temporary seeding.

3.3 Permanent cover or final stabilization methods are used to prevent erosion, such as the placement of riprap, sodding, or permanent seeding or planting. Permanent seeding and planting must have a uniform perennial vegetation cover of at least 70 percent density to constitute final stabilization.

### 4. Inspection and Maintenance

4.1 The Permittee shall ensure that temporary protection and permanent cover for the exposed areas at the site are maintained.

4.2 Site inspections shall be conducted at least once every two months during non-frozen conditions. Inspections shall be conducted by appropriately trained personnel at the facility site per the facility's Storm Water Pollution Prevention Plan (SWPPP). The purpose of inspections is to 1) determine whether structural and non-structural BMPs require maintenance or changes, and 2) evaluate the completeness and accuracy of the SWPPP. At least one inspection during a reporting period shall be conducted while storm water is discharging from the facility.

4.3 Inspections shall be documented and a copy of all documentation shall remain on the permitted site and be available upon request. Indicate the date and time of the inspection as well as the name of the inspector on the inspection form.

4.4 The following compliance items will be inspected, and documented where appropriate:

a. evaluate the facility to determine that the SWPPP accurately reflects site conditions;

b. evaluate the facility to determine whether new exposed materials have been added to the site since completion of the SWPPP, and document any new significant materials;

c. during the inspection conducted during the runoff event, observe the runoff to determine if it is discolored or otherwise visibly contaminated, and document observations; and,

d. determine if the non-structural and structural BMPs as indicated in the SWPPP are installed and functioning properly.

4.5 If the findings of a site inspection indicate that BMPs are not meeting the objectives of the SWPPP corrective actions must be initiated within 30 days and the BMPs restored to full operation as soon as field conditions allow.

## Chapter 7. Stormwater

### 4. Inspection and Maintenance

4.6 The Permittee shall minimize vehicle tracking of gravel, soil or mud.

### 5. Sedimentation Basin Design and Construction

5.1 Inlet(s) and outlet(s) shall be designed to prevent short circuiting and the discharge of floating debris.

5.2 The inlet(s) shall be placed at an elevation at least above one-half of the basin design hydraulic storage volume.

5.3 The outlet(s) shall consist of a perforated riser pipe wrapped with filter fabric and covered with crushed gravel. The perforated riser pipe shall be designed to allow complete drawdown of the basin(s).

5.4 Permanent erosion control, such as riprap, splash pads or gabions shall be installed at the outlet(s) to prevent downstream erosion.

5.5 The basins shall be designed to allow for regular removal of accumulated sediment by a backhoe or other suitable equipment.

5.6 New sedimentation basins shall be designed by a registered professional engineer, and installed under the direct supervision of a registered professional engineer.

5.7 Basins shall provide at least 1800 cubic feet, per acre drained, of hydraulic storage volume below the top of the outlet riser pipe.

### 6. Application of Chemical Dust Suppressants

6.1 If a material applied is mixed with water or another solvent before application, the chemical analysis shall be done on the aqueous or other mixture that is representative of the solution applied. This analysis shall be conducted during the same calendar year of application. This analysis shall include the parameters that may be determined by U.S. Environmental Protection Agency (EPA) Methods 624 and 625 which are described in 40 CFR Part 136.

6.2 The Chemical Dust Suppressant Annual Report shall include:

a. a record of the dates, methods, locations and amounts by volume of application at the facility;

b. whether the product was applied in the preceding year; and

c. the results of a chemical analysis of the materials applied each year.

6.3 In areas that runoff to the surface receiving water identified on Page 1 of this permit (Mississippi River), chemical dust suppressants, if used, shall not be applied within 100 feet of the Mississippi River. These materials also shall not be applied within 100 feet of ditches that conduct surface flow to the Mississippi River.

6.4 If chemical dust suppressants are applied, the Permittee shall submit a Chemical Dust Suppressant Annual Report due March 31 of each calendar year following the application of a chemical dust suppressant.

## Chapter 8. Chemical Additives

### 1. General Requirements

1.1 The Permittee shall receive prior written approval from the MPCA before increasing the use of a chemical additive authorized by this permit, or using a chemical additive not authorized by this permit. "Chemical additive" includes processing reagents, water treatment products, cooling water additives, freeze conditioning agents, chemical dust suppressants, detergents and solvent cleaners used for equipment and maintenance cleaning, among other materials.

1.2 The Permittee shall request approval for an increased or new use of a chemical additive 60 days before the proposed increased or new use.

## Chapter 8. Chemical Additives

### 1. General Requirements

1.3 This written request shall include the following information for the proposed additive:

a. Material Safety Data Sheet.

b. A complete product use and instruction label.

c. The commercial and chemical names of all ingredients.

d. Aquatic toxicity and human health or mammalian toxicity data including a carcinogenic, mutagen.. teratogenic concern or rating.

e. Environmental fate information including, but not limited to, persistence, half-life, intermediate breakdow products, and bioaccumulation data.

f. The proposed method, concentration, and average and maximum rates of use.

g. If applicable, the number of cycles before wastewater bleedoff

h. If applicable, the ratio of makeup flow to discharge flow.

1.4 This permit may be modified to restrict the use or discharge of a chemical additive.

## Chapter 9. Total Facility Requirements

### 1. General Permit Requirements

**Definitions**

1.1 "Calendar Month Average" is calculated by adding all daily values measured during a calendar month and dividing by the number of daily values measured during that month. The "Calendar Month Average" limit is an upper limit.

1.2 "Calendar Month Maximum" is the highest value of single samples taken throughout the month. The "Calendar Month Maximum" is an upper limit.

1.3 "Calendar Month Minimum" is the lowest value of single samples taken throughout the month. The "Calendar Month Minimum" is a lower limit.

1.4 "Calendar Month Total" is calculated by adding all daily values measured during a calendar month. It is usually expressed in mass or volume units. The "Calendar Month Total" is an upper limit.

1.5 "Daily Maximum" means the maximum allowable discharge of pollutant during a calendar day. Where daily maximum limitations are expressed in units of mass, the daily discharge is the total mass discharged over the course of the day. Where daily maximum limitations are expressed in terms of a concentration, the daily discharge is the arithmetic average measurement of the pollutant concentration derived from all measurements taken that day. The "Daily Maximum" is an upper limit.

1.6 "Grab" sample type is an individual sample collected from one location at one point in time.

1.7 "Instantaneous Maximum" is the highest value recorded when continuous monitoring is used or when the reporting frequency is not specifically defined. The "Instantaneous Maximum" limit is an upper limit. The highest value recorded is reported.

1.8 "Single Value" in the context of this permit is in reference to temperature limitations described under thermal limitations, where applicable, or to a temperature monitoring requirement.

## Chapter 9. Total Facility Requirements

### 1. General Permit Requirements

1.9 "Stormwater" means stormwater runoff, snow melt runoff, and surface runoff and drainage.

**General Conditions**

1.10 Incorporation by Reference. The following applicable federal and state laws are incorporated by reference in this permit, are applicable to the Permittee, and are enforceable parts of this permit: 40 CFR pts. 122.41, 122.42, 136, 403 and 503; Minn. R. pts. 7001, 7041, 7045, 7050, 7060, and 7080; and Minn. Stat. Sec. 115 and 116.

1.11 Permittee Responsibility. The Permittee shall perform the actions or conduct the activity authorized by the permit in compliance with the conditions of the permit and, if required, in accordance with the plans and specifications approved by the Agency. (Minn. R. 7001.0150, subp. 3, item E)

1.12 Toxic Discharges Prohibited. Whether or not this permit includes effluent limitations for toxic pollutants, the Permittee shall not discharge a toxic pollutant except according to Code of Federal Regulations, Title 40, sections 400 to 460 and Minnesota Rules, parts 7050.0100 to 7050.0220 and 7052.0010 to 7052.0110 (applicable to toxic pollutants in the Lake Superior Basin) and any other applicable MPCA rules. (Minn. R. 7001.1090, subp.1, item A)

1.13 Nuisance Conditions Prohibited. The Permittee's discharge shall not cause any nuisance conditions including, but not limited to: floating solids, scum and visible oil film, acutely toxic conditions to aquatic life, or other adverse impact on the receiving water. (Minn. R. 7050.0210 subp. 2)

1.14 Property Rights. This permit does not convey a property right or an exclusive privilege. (Minn. R. 7001.0150, subp. 3, item C)

1.15 Liability Exemption. In issuing this permit, the state and the MPCA assume no responsibility for damage to persons, property, or the environment caused by the activities of the Permittee in the conduct of its actions, including those activities authorized, directed, or undertaken under this permit. To the extent the state and the MPCA may be liable for the activities of its employees, that liability is explicitly limited to that provided in the Tort Claims Act. (Minn. R. 7001.0150, subp. 3, item O)

1.16 The MPCA's issuance of this permit does not obligate the MPCA to enforce local laws, rules, or plans beyond what is authorized by Minnesota Statutes. (Minn. R. 7001.0150, subp.3, item D)

1.17 Liabilities. The MPCA's issuance of this permit does not release the Permittee from any liability, penalty or duty imposed by Minnesota or federal statutes or rules or local ordinances, except the obligation to obtain the permit. (Minn. R. 7001.0150, subp.3, item A)

1.18 The issuance of this permit does not prevent the future adoption by the MPCA of pollution control rules, standards, or orders more stringent than those now in existence and does not prevent the enforcement of these rules, standards, or orders against the Permittee. (Minn. R. 7001.0150, subp.3, item B)

1.19 Severability. The provisions of this permit are severable, and if any provisions of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

1.20 Compliance with Other Rules and Statutes. The Permittee shall comply with all applicable air quality, solid waste, and hazardous waste statutes and rules in the operation and maintenance of the facility.

1.21 Inspection and Entry. When authorized by Minn. Stat. Sec. 115.04; 115B.17, subd. 4; and 116.091, and upon presentation of proper credentials, the agency, or an authorized employee or agent of the agency, shall be allowed by the Permittee to enter at reasonable times upon the property of the Permittee to examine and copy books, papers, records, or memoranda pertaining to the construction, modification, or operation of the facility covered by the permit or pertaining to the activity covered by the permit; and to conduct surveys and investigations, including sampling or monitoring, pertaining to the construction, modification, or operation of the facility covered by the permit or pertaining to the activity covered by the permit. (Minn. R. 7001.0150, subp.3, item I)

## Chapter 9. Total Facility Requirements

### 1. General Permit Requirements

1.22 Control Users. The Permittee shall regulate the users of its wastewater treatment facility so as to prevent the introduction of pollutants or materials that may result in the inhibition or disruption of the conveyance system, treatment facility or processes, or disposal system that would contribute to the violation of the conditions of this permit or any federal, state or local law or regulation.

**Sampling**

1.23 Representative Sampling. Samples and measurements required by this permit shall be conducted as specified in this permit and representative of the discharge or monitored activity. (40 CFR 122.41 (j)(1))

1.24 Additional Sampling. If the Permittee monitors more frequently than required, the results and the frequency of monitoring shall be reported on the Discharge Monitoring Report (DMR) or another MPCA-approved form for that reporting period. (Minn. R. 7001.1090, subp. 1, item E)

1.25 Certified Laboratory. A laboratory certified by the Minnesota Department of Health shall conduct analyses required by this permit. Analyses of dissolved oxygen, pH, temperature and total residual oxidants (chlorine, bromine) do not need to be completed by a certified laboratory but shall comply with manufacturers specifications for equipment calibration and use. (Minn. Stat. Sec. 144.97 through 144.98 and Minn. R. 4740.2010 through 4740.2040)

1.26 Sample Preservation and Procedure. Sample preservation and test procedures for the analysis of pollutants shall conform to 40 CFR Part 136 and Minn. R. 7041.3200.

1.27 Equipment Calibration. All monitoring and analytical instruments used to monitor as required by this permit shall be calibrated and maintained at a frequency necessary to ensure accuracy. Flow monitoring equipment should be calibrated at least twice annually. For facilities with lift stations/pumps, calibration shall be completed at least twice annually. The Permittee shall maintain written records of all calibrations and maintenance for at least three years. (Minn. R. 7001.0150, subp. 2, items B and C)

1.28 Unless otherwise approved, instruments used to measure metered flows shall be accurate within plus or minus 10 percent of the true flow values. Flow for non-metered systems (e.g., screenwash return) shall be estimated using methods such as pump discharge curves and run times. SD 001 discharge flow shall be determined by comparing discharge canal sluice gate position and canal water elevation to the applicable engineering flow curves.

1.29 Maintain Records. The Permittee shall keep the records required by this permit for at least three years, including any calculations, original recordings from automatic monitoring instruments, and laboratory sheets. The Permittee shall extend these record retention periods upon request of the MPCA. The Permittee shall maintain records for each sample and measurement. The records shall include the following information (Minn. R. 7001.0150, subp. 2, item C):

a. The exact place, date, and time of the sample or measurement;

b. The date of analysis;

c. The name of the person who performed the sample collection, measurement, analysis, or calculation; and

d. The analytical techniques, procedures and methods used; and

e. the results of the analysis. (Minn. R. 7001.0150, subp. 2, item C)

## Chapter 9. Total Facility Requirements

### 1. General Permit Requirements

1.30 Completing Reports. The Permittee shall submit the results of the required sampling and monitoring activities on the forms provided, specified, or approved by the MPCA. The information shall be recorded in the specified areas on those forms and in the units specified. (Minn. R. 7001.1090, subp. 1, item D; Minn. R. 7001.0150, subp. 2, item B)

Required forms may include:

Discharge Monitoring Reports (DMRs)
The results of the monitoring and sampling required in this permit shall be recorded on the (grey and white) DMRs which, if required, will be provided by the MPCA. If no discharge occurred during the reporting period, the Permittee shall check the "No Discharge" box on the DMR. Note: Every open, white box must be filled-in on the DMR, unless no discharge occurred during the reporting period.

Supplemental Report Form (SRFs)
Individual values for each sample and measurement must be recorded on the SRF which, if required, will be provided by the MPCA. SRFs shall be submitted with the appropriate DMRs. You may design and use your own SRF, however it must be approved by the MPCA. Note: Required Summary information MUST also be recorded on the DMR. Summary information that is submitted ONLY on the SRF does not comply with the reporting requirements.

Other Reports and Forms
Other reports and information required by this permit shall be recorded on a form supplied or approved by the MPCA and submitted by the date specified in the permit. (Minn. R. 7001.1090, subp. 1, item D and Minn. R. 7001.0150, subp. 2, item B)

1.31 Submitting Reports. DMRs and SRFs shall be submitted to:

MPCA
Attn: Discharge Monitoring Reports
520 Lafayette Road North
St. Paul, Minnesota 55155-4194.

DMRs and SRFs shall be submitted or postmarked by the 21st day of the month following the sampling period or as otherwise specified in this permit. A DMR shall be submitted for each required station even if no discharge occurred during the reporting period. (Minn. R. 7001.0150, subps. 2.B and 3.H)

Other reports required by this permit shall be submitted or postmarked by the date specified in the permit to:

MPCA
Attn: WQ Submittals Center
520 Lafayette Road North
St. Paul, Minnesota 55155-4194

1.32 Incomplete or Incorrect Reports. The Permittee shall immediately submit an amended report or DMR to the MPCA upon discovery by the Permittee or notification by the MPCA that it has submitted an incomplete or incorrect report or DMR. The amended report or DMR shall contain the missing or corrected data along with a cover letter explaining the circumstances of the incomplete or incorrect report. (Minn. R. 7001.0150 subp. 3, item G)

## Chapter 9. Total Facility Requirements

### 1. General Permit Requirements

1.33 Required Signatures. All DMRs, forms, reports, and other documents submitted to the MPCA shall be signed by the Permittee or the duly authorized representative of the Permittee. Minn. R. 7001.0150, subp. 2, item D. The person or persons that sign the DMRs, forms, reports or other documents must certify that he or she understands and complies with the certification requirements of Minn. R. 7001.0070 and 7001.0540, including the penalties for submitting false information. Technical documents, such as design drawings and specifications and engineering studies required to be submitted as part of a permit application or by permit conditions, must be certified by a registered professional engineer. (Minn. R. 7001.0540)

1.34 Detection Level. The Permittee shall report monitoring results below the reporting limit (RL) of a particular instrument as "<" the value of the RL. For example, if an instrument has a RL of 0.1 mg/L and a parameter is not detected at a value of 0.1 mg/L or greater, the concentration shall be reported as "<0.1 mg/L". "Non-detected ", "undetected ", "below detection limit ", and "zero" are unacceptable reporting results, and are permit reporting violations. (Minn. R. 7001.0150, subp. 2, item B)

1.35 Records. The Permittee shall, when requested by the Agency, submit within a reasonable time the information and reports that are relevant to the control of pollution regarding the construction, modification, or operation of the facility covered by the permit or regarding the conduct of the activity covered by the permit. (Minn. R. 7001.0150, subp. 3, item H)

1.36 Confidential Information. Except for data determined to be confidential according to Minn. Stat. Sec. 116.075, subd. 2, all reports required by this permit shall be available for public inspection. Effluent data shall not be considered confidential. To request the Agency maintain data as confidential, the Permittee must follow Minn. R. 7000.1300.

**Noncompliance and Enforcement**

1.37 Subject to Enforcement Action and Penalties. Noncompliance with a term or condition of this permit subjects the Permittee to penalties provided by federal and state law set forth in section 309 of the Clean Water Act; United States Code, title 33, section 1319, as amended; and in Minn. Stat. Sec. 115.071 and 116.072, including monetary penalties, imprisonment, or both. (Minn. R. 7001.1090, subp. 1, item B)

1.38 Criminal Activity. The Permittee may not knowingly make a false statement, representation, or certification in a record or other document submitted to the Agency. A person who falsifies a report or document submitted to the Agency, or tampers with, or knowingly renders inaccurate a monitoring device or method required to be maintained under this permit is subject to criminal and civil penalties provided by federal and state law. (Minn. R. 7001.0150, subp.3, item G., 7001.1090, subps. 1, items G and H and Minn. Stat. Sec. 609.671)

1.39 Noncompliance Defense. It shall not be a defense for the 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. ( 40 CFR 122.41(c))

1.40 Effluent Violations. If sampling by the Permittee indicates a violation of any discharge limitation specified in this permit, the Permittee shall immediately make every effort to verify the violation by collecting additional samples, if appropriate, investigate the cause of the violation, and take action to prevent future violations. Violations that are determined to pose a threat to human health or a drinking water supply, or represent a significant risk to the environment shall be immediately reported to the Minnesota Department of Public Safety Duty Officer at 1(800)422-0798 (toll free) or (651)649-5451 (metro area). In addition, you may also contact the MPCA during business hours. Otherwise the violations and the results of any additional sampling shall be recorded on the next appropriate DMR or report.

1.41 Unauthorized Releases of Wastewater Prohibited. Except for conditions specifically described in Minn. R. 7001.1090, subp. 1, items J and K, all unauthorized bypasses, overflows, discharges, spills, or other releases of wastewater or materials to the environment, whether intentional or not, are prohibited. However, the MPCA will consider the Permittee's compliance with permit requirements, frequency of release, quantity, type, location, and other relevant factors when determining appropriate action. (40 CFR 122.41 and Minn. Stat. Sec 115.061)

## Chapter 9. Total Facility Requirements

### 1. General Permit Requirements

1.42 Upset Defense. In the event of temporary noncompliance by the Permittee with an applicable effluent limitation resulting from an upset at the Permittee's facility due to factors beyond the control of the Permittee, the Permittee has an affirmative defense to an enforcement action brought by the Agency as a result of the noncompliance if the Permittee demonstrates by a preponderance of competent evidence:

a. The specific cause of the upset;

b. That the upset was unintentional;

c. That the upset resulted from factors beyond the reasonable control of the Permittee and did not result from operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventative maintenance, or increases in production which are beyond the design capability of the treatment facilities;

d. That at the time of the upset the facility was being properly operated;

e. That the Permittee properly notified the Commissioner of the upset in accordance with Minn. R. 7001.1090, subp. 1, item I; and

f. That the Permittee implemented the remedial measures required by Minn. R. 7001.0150, subp. 3, item J.

**Operation and Maintenance**

1.43 The Permittee shall at all times properly operate and maintain the facilities and systems of treatment and control, and the appurtenances related to them which are installed or used by the Permittee to achieve compliance with the conditions of the 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. The Permittee shall install and maintain appropriate backup or auxiliary facilities if they are necessary to achieve compliance with the conditions of the permit and, for all permits other than hazardous waste facility permits, if these backup or auxiliary facilities are technically and economically feasible Minn. R. 7001.0150. subp. 3, item F.

1.44 In the event of a reduction or loss of effective treatment of wastewater at the facility, the Permittee shall control production or curtail its discharges to the extent necessary to maintain compliance with the terms and conditions of this permit. The Permittee shall continue this control or curtailment until the wastewater treatment facility has been restored or until an alternative method of treatment is provided. (Minn. R. 7001.1090, subp. 1, item C)

1.45 Solids Management. The Permittee shall properly store, transport, and dispose of biosolids, septage, sediments, residual solids, filter backwash, screenings, oil, grease, and other substances so that pollutants do not enter surface waters or ground waters of the state. Solids should be disposed of in accordance with local, state and federal requirements. (40 CFR 503 and Minn. R. 7041 and applicable federal and state solid waste rules)

1.46 Intake traveling screen rinse water and contents will be returned to the river uninterrupted for the protection of fish and other aquatic organisms.

1.47 Scheduled Maintenance. The Permittee shall schedule maintenance of the treatment works during non-critical water quality periods to prevent degradation of water quality, except where emergency maintenance is required to prevent a condition that would be detrimental to water quality or human health. ( Minn. R. 7001.0150. subp. 3, item F and Minn. R. 7001.0150. subp. 2, item B)

1.48 Control Tests. In-plant control tests shall be conducted at a frequency adequate to ensure compliance with the conditions of this permit. (Minn. R. 7001.0150. subp. 3, item F and Minn. R. 7001.0150. subp. 2, item B)

**Changes to the Facility or Permit**

## Chapter 9. Total Facility Requirements

### 1. General Permit Requirements

1.49 Permit Modifications. No person required by statute or rule to obtain a permit may construct, install, modify, o operate the facility to be permitted, nor shall a person commence an activity for which a permit is required by statute or rule until the Agency has issued a written permit for the facility or activity. (Minn. R. 7001.0030)

Permittees that propose to make a change to the facility or discharge that requires a permit modification must follow Minn. R. 7001.0190. If the Permittee cannot determine whether a permit modification is needed, the Permittee must contact the MPCA prior to any action. It is recommended that the application for permit modification be submitted to the MPCA at least 180 days prior to the planned change.

1.50 Report Changes. The Permittee shall immediately report to the MPCA (Minn. R. 7001.0150, subp. 3, item M.):

a. Any substantial changes in operational procedures;

b. Activities which alter the nature or frequency of the discharge; and

c. Material factors affecting compliance with the conditions of this permit. (Minn. R. 7001.0150, subp. 3, ite M. )

1.51 MPCA Initiated Permit Modification, Suspension, or Revocation. The MPCA may modify or revoke and reissue this permit pursuant to Minn. R. 7001.0170. The MPCA may revoke without reissuance this permit pursuant to Minn. R. 7001.0180.

1.52 Permit Transfer. The permit is not transferable to any person without the express written approval of the Agency after compliance with the requirements of Minn. R. 7001.0190. A person to whom the permit has been transferred shall comply with the conditions of the permit. (Minn. R., 7001.0150, subp. 3, item N)

1.53 Permit Reissuance. If the Permittee desires to continue permit coverage beyond the date of permit expiration, the Permittee shall submit an application for reissuance at least 180 days before permit expiration. If the Permittee does not intend to continue the activities authorized by this permit after the expiration date of this permit, the Permittee shall notify the MPCA in writing at least 180 days before permit expiration.

If the Permittee has submitted a timely application for permit reissuance, the Permittee may continue to conduct the activities authorized by this permit, in compliance with the requirements of this permit, until the MPCA takes final action on the application, unless the MPCA determines any of the following (Minn. R. 7001.0040 and 7001.0160):

a. The Permittee is not in substantial compliance with the requirements of this permit, or with a stipulation agreement or compliance schedule designed to bring the Permittee into compliance with this permit;

b. The MPCA, as a result of an action or failure to act by the Permittee, has been unable to take final action on the application on or before the expiration date of the permit;

c. The Permittee has submitted an application with major deficiencies or has failed to properly supplement the application in a timely manner after being informed of deficiencies. (Minn. R. 7001.0040 and 7001.0160)

## Appendix 1:

**Table 1.** Minimum number of samples for sediment evaluation

| VOLUME PLANNED FOR REMOVAL in CUBIC YARDS | NUMBER OF CORE SAMPLE SITES |
|---|---|
| 0-30,000 | 3 |
| 30,000-100,000 | 5 |
| 100,000-500,000 | 6 |
| 500,000-1,000,000 | 8 |
| >1,000,000 | >8 |

**Table 2. Baseline Sediment Parameter List**

| Parameter | Analytical Method | Method Detection Limit (mg/kg, dry weight unless noted) | Tier 1 Soil Reference Value (SRV) (mg/kg, dry weight unless noted) | Tier 2 Soil Reference Value (SRV) (mg/kg, dry weight unless noted) |
|---|---|---|---|---|
| **Inorganics – Metals** | | | | |
| Arsenic | SW-846 3050B/6010B EPA 6010 or 7060 | 0.42 | 5 | 20 |
| Cadmium | SW-846 3050B/6010B EPA 7131 | 0.02 | 25 | 160 |
| Chromium III | SW-846 3050B/6010B EPA 6010 or 7191 | 0.058 | 44,000 | 100,000 |
| Chromium VI | SW-846 3050B/6010B EPA 6010 or 7191 | 0.058 | 87 | 650 |
| Copper | SW-846 3050B/6010B EPA 6010 or 7211 | 0.1 | 11 | 9,000 |
| Lead | SW-846 3050B/6010B EPA 6010 or 7421 | 0.22 | 300 | 700 |
| Mercury | SW-846 7471A EPA 7471 | 0.02 | 0.5 | 1.5 |
| Nickel | SW-846 3050B/6010B EPA 6010 | 0.36 | 560 | 2,500 |
| Selenium | SW-846 3050B/6010B | 0.43 | 160 | 1,250 |
| Zinc | SW-846 3050B/6010B EPA 6010 or 7951 | 0.35 | 8,700 | 70,000 |
| **Inorganics – Nutrients** | | | | |
| Total Phosphorus | EPA 365.2/365.3 | 50 | | |
| Nitrate + Nitrite | | | | |
| Ammonia-Nitrogen | | | | |
| Total Kjeldahl Nitrogen | | | | |
| **Organics** | | | | |
| PCBs (Total) | SW-846 8081<br>EPA 8081, 3540B, 3541 | 0.02 | 1.2 | 8 |
| Total Organic Carbon | SW 846 8081 SW846-EPA 9060 | 0.2% | | |
| **Physical Tests** | | | | |
| Sieve and Hydrometer Analysis | ASTM D-422 | | | |
| Moisture Content | ASTM D-2216 | | | |

**Table 3. Additional Sediment Parameter List**

| Parameter | Analytical Method | Method Detection Limit (mg/kg, dry weight unless noted) | Tier 1 Soil Reference Value (SRV) (mg/kg, dry weight unless noted) | Tier 2 Soil Reference Value (SRV) (mg/kg, dry weight unless noted) |
|---|---|---|---|---|
| **Inorganics – Metals** | | | | |
| Barium | SW-846 3050B/6010B | 0.049 | 1,200 | 11,000 |
| Cyanide | SW-846 9012A | 0.5 | 62 | 5,000 |
| Manganese | SW-846 3050B/6010B | 0.39 | 3,600 | 8,100 |
| **Inorganics – Nutrients** | | | | |
| Oil & Grease | SW-846 9070 | | | |
| **Organics** | | | | |
| Aldrin | SW-846 8081 EPA 8081, 354440B, 3541 | 0.00044 | 1 | 2 |
| Chlordane | SW-846 8081 EPA 8081, 354440B, 3541 | 0.01 | 13 | 74 |
| Endrin | SW-846 8081 EPA 8081, 354440B, 3541 | 0.00073 | 8 | 56 |
| Dieldrin | SW-846 8081 EPA 8081, 354440B, 3541 | 0.00091 | 0.8 | 2 |
| Heptachlor | SW-846 8081 EPA 8081, 354440B, 3541 | 0.00077 | 2 | 3.5 |
| Lindane (Gamma BHC) | SW-846 8081 EPA 8081, 354440B, 3541 | 0.00029 | 9 | 15 |
| DDT | SW-846 8081 EPA 8081, 354440B, 3541 | 0.00063 | 15 | 88 |
| DDD | SW-846 8081 EPA 8081, 354440B, 3541 | 0.0002 | 56 | 125 |
| DDE | SW-846 8081 EPA 8081, 354440B, 3541 | 0.0002 | 40 | 90 |
| Toxaphene | SW-846 8081 | 0.003 | 13 | 28 |
| 2,3,7,8-dioxin, 2,3,7,8-furan and 15 2,3,7,8-substituted dioxin and furan congeners | EPA 8290 | 1-10 pg/g | 0.00002 | 0.00003 |
| Polycyclic Aromatic Hydrocarbons (PAHs) | | | | |
| Naphthalene | EPA 8310 | 176 ug/kg | 10 | 28 |
| Pyrene | EPA 8310 | 195 ug/kg | 890 | 5,800 |
| Fluorene | EPA 8310 | 77.4 ug/kg | 850 | 4,120 |
| Acenapthene | EPA 8310 | 6.7 ug/kg | 1,200 | 5,200 |
| Anthracene | EPA 8310 | 57.2 ug/kg | 7,880 | 45,400 |
| Fluoranthene | EPA 8310 | 423 ug/kg | 1,080 | 6,800 |
| Benzo (a) pyrene (BAP)/BAP equivalent | EPA 8310 | 150 ug/kg | 2 | 4 |
| Benzo (a) anthracene | EPA 8310 | 108 ug/kg | The results for these analytes should be added together and treated as the BAP equivalent, which is compared against the soil reference value for Benzo (a) pyrene, above. | |
| Benzo (e) pyrene | EPA 8310 | 150 ug/kg | | |
| Benzo (b) fluoranthene | EPA 8310 | 240 ug/kg | | |
| Benzo (ghi) perylene | EPA 8310 | 170 ug/kg | | |
| Benzo (k) fluoranthene | EPA 8310 | 240 ug/kg | | |

| | | | | |
|---|---|---|---|---|
| Chrysene | EPA 8310 | 166 ug/kg | | |
| Dibenzo(ah)anthracene | EPA 8310 | 33 ug/kg | | |
| Indeno (1,2,3-cd) pyrene | EPA 8310 | 200 ug/kg | | |
| **Physical Tests** | | | | |
| Atterburg Limits (Liquid Limit and Plastic Limit) | ASTM D4318 | | | |
| Specific Gravity | ASTM D-854 | | | |

Table 4. Contaminants and Source Industries. Adapted from Inland Testing Manual (EPA/Corps, 1998)

| | Acenapthene | Aldrin | Ammonia | Aniline | Arsenic | Benzo(a)anthracene | Benzo(a)pyrene | Cadmium | Chlordane | Chromium | Copper | Cyanide | DDE | DDT | Dieldrin | Endrin | Ethyl Parathion | Fluoranthene | Heptachlor | Hexachlorobenzene | Hexachlorocyclopentadiene | Lead | Mercury | 2-Methylnaphthalene | Nickel | Oil and Grease | Organotin / Tin | PCB | Phenanthrene | Phosphorus | Pyrene | Selenium | Tetrachlorodibenzodioxin (TCDD) | Tetrachlorodibenzofuran (TCDF) | Toxaphene | Zinc |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Aluminum Die-casting | | | | | | | | ■ | | ■ | | | | | | | | | | | | | | | ■ | ■ | | ■ | | | | | | | | |
| Ammunitions | | | | | | | | | | | ■ | | | | | | | | | | | | | | | | | | | ■ | | | | | | ■ |
| Anti-fouling Paints | | | | | | | | | | | ■ | | | | | | | | | | | ■ | ■ | | | | ■ | | | | | | | | | |
| Automotive | | | | | ■ | | ■ | ■ | | ■ | ■ | | | | | | | | | | | | | | | ■ | | ■ | | | | | | | | ■ |
| Batteries | | | | | | | | | | | | | | | | | | | | | ■ | ■ | | | | | | | | | | | | | | |
| Boat Manufacturing, Boat Repair | | | | | | ■ | ■ | ■ | | ■ | ■ | | | | | | | ■ | | | | | ■ | | | ■ | ■ | ■ | ■ | | ■ | ■ | | | | ■ |
| Boat Refueling | | | | | | ■ | ■ | | | | | | | | | | | ■ | | | | | | | | ■ | | | ■ | | ■ | | | | | |
| Chemical Manufacturing | | | ■ | | | | | ■ | | ■ | | | | | | | | | | | | | ■ | ■ | | ■ | | | | | | ■ | | | ■ | |
| Coal Gasification (MGP) | ■ | | | | | ■ | ■ | | | | | ■ | | | | | | ■ | | | | | | ■ | | ■ | | | ■ | | ■ | | | | | |
| Commercial Farming | ■ | ■ | ■ | | | | | | | | | | | ■ | ■ | | | | | | | | | | | | | | | ■ | | | | | ■ | |
| Corrosion Metallurgy | | | | | | | | | | ■ | ■ | ■ | | | | | | | | | | ■ | | | ■ | | | | | | | | | | | ■ |
| Dairy | | | ■ | | | | | | | | | | | | | | | | | | | | | | | | | | | ■ | | | | | | |
| Detergents / Surfactants | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | ■ | | | | | | ■ |
| Dye | ■ | | | ■ | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Electrical | | | | | | | | ■ | | | ■ | | | | | | | | | | | ■ | ■ | | ■ | | | ■ | | | | ■ | | | | ■ |
| Explosives | | | ■ | | | | | | | | ■ | | | | | | | | | | | | | | | | | | | | | | | | | |
| Fish and Wildlife Consumption Advisory | | | | | | | | | | | | | | | | | | | | | | | ■ | | | | | ■ | | | | | | | | |
| Fruits and Vegetables | | | ■ | | | | | | | | | | | | | | | | | | | | | | | | | | | ■ | | | | | | |
| Leather / Tanning | | | | | | | | | | ■ | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Meat Products | | | ■ | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Metal Finishing / Refining | | | | ■ | ■ | | ■ | ■ | | ■ | ■ | ■ | | | | | | | | | ■ | ■ | | | ■ | ■ | | | | | | | | | | ■ |
| Metalurgical Processes | | | | | ■ | | | | | | | | | | | | | | | | | | | | ■ | ■ | | | | | | | | | | ■ |
| Nitric Acid Manufacturing | | | ■ | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Oxide Manufacturing | | | | | | | | | | ■ | ■ | | | | | | | | | | | | | | | | | | | | | | | | | ■ |
| Pesticides / Fertilizers | ■ | ■ | ■ | | | | | | | | | | | | ■ | ■ | ■ | | ■ | ■ | | | | | | | | | | ■ | | | | | ■ | |
| Petroleum Refining | | | ■ | | | | | | | | | | | | | | | | | | | ■ | | | | | | | | | | ■ | ■ | ■ | | |
| Phosphate Mining | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | ■ | | | | | | |
| Photographic | | | | | ■ | | | | | ■ | | | | | | | | | | | | | | | | | | | | ■ | | ■ | | | | |
| Pigments / Inks | | | ■ | ■ | | | | | | | | | | | | | | | | | | ■ | ■ | | | | | | | | | ■ | | | | |
| Plastics | ■ | | | | | | | | | | | | | | | | | | | | | ■ | | | | | | | | | | | | | | |
| Printing Plates | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | ■ | | | | | | ■ |
| Pulp and Paper Mills | | | | | | | | | | | | | | | | | | | | | | | ■ | | ■ | ■ | | | | | | | ■ | ■ | | |
| Rubber | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | ■ | | | | ■ |
| Steam Power | | | | ■ | ■ | | ■ | ■ | | ■ | ■ | | | | | | | | | | | ■ | | | ■ | | | | | | | | | | | |
| Steel / Iron | | | ■ | ■ | ■ | ■ | ■ | | | | | ■ | | | | | | | | | | ■ | | | | ■ | | ■ | ■ | ■ | ■ | | | | | ■ |
| Sulferic Acid | | | ■ | ■ | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Textiles | | | ■ | | | | ■ | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Utilities | | | | | | | | | | | | | | | | | | | | | | | ■ | | | | | | ■ | ■ | | ■ | | | | ■ |
| Valuable Mineral Mining | | | | | | | | | | | | ■ | | | | | | | | | | ■ | | | | | | | | | | | | | | ■ |
| Waste Water Treatment Plants | | | ■ | | | | | | ■ | ■ | ■ | | | | | | | | | | | ■ | ■ | | ■ | ■ | | ■ | | ■ | ■ | | | | | ■ |

## NPDES LIMITS
11/1/04

| PARAMETER | LIMIT | RESTRICTIONS |
|---|---|---|
| **EMERGENCY INTAKE TREATMENT** | | |
| Biocide | Per request/approval letters | Restrictions per approval letters. |
| Intake Pipe Back-Flushing | NA | Back-flush intake piping periodically to remove accumulated river sediment. Displaced sediment from the pipe would not be removed from the river, only shifted some distance away from intake pipe suction. |
| Hydro Lasing Emergency Intake Gates | NA | Periodic cleaning of emergency intake gates. The water and river silt is discharged into the plant intake canal. |
| **COOLING WATER & CONDENSER CIRCULATING WATER (DISCHARGE SD001)** | | |
| **PARAMETER** | **LIMIT** | **RESTRICTIONS** |
| Total Residual Oxidant, Bromine Used | Intermittent 0.05 ppm (Instantaneous Max) Continuous = 0.001 ppm | Intermittent by daily grab sample. Continuous by daily calculation. |
| Total Residual Oxidant, Chlorine Used | Intermittent = 0.2 ppm (Instantaneous Max) Continuous = 0.04 ppm | Intermittent by daily grab sample. Continuous by daily calculation, but may be done by analysis. |
| pH | 6.0 - 9.0 | Shall be monitored by weekly grab samples. Limits are not subject to averaging and shall be met at all times. |
| Oil or Other Substances | No visible color film on surface of receiving waters. | NA |
| Floating Solids or Visible Foam | Trace Amounts | NA |
| Biocide | Per request/approval letters | Used for Zebra mussel control, with restrictions per approval letters. |
| **CHILLED WATER, CONTAINMENT, AND ZX SYSTEM (SD001)** | | |
| **PARAMETER** | **LIMIT** | **RESTRICTIONS** |
| Nitrite Based Inhibitor with Additives | 0 - 900 ppm | Corrosion inhibitor in the chilled water system. 700 to 900 ppm normal operating range. |
| Microbiocide | 0 - 200 ppm | Used for microbiological attack in closed loop systems. Has been used in the containment chillers. |
| Molybdate Based Corrosion Inhibitor | 0 – 70 ppm | Used in the containment chillers. |

## NPDES LIMITS

11/1/04

| STEAM GENERATOR BLOWDOWN (DISCHARGE SD002) | | |
|---|---|---|
| PARAMETER | LIMIT | RESTRICTIONS |
| Boric Acid | 0 - 5000 ppm | 0 - 10 ppm is routine range. Boron is added in higher concentrations for S/G crevice flushing. |
| Hydrazine | 0 - 150 ppm | Normal operating range 0 - 125 ppb in the feedwater. Wet lay-up range 50 - 100 ppm. |
| Carbohydrazide | 0 - 150 ppm | Carbohydrazide may be used in conjunction with or in place of hydrazine. Used during S/G wet lay up. |
| Ammonium Hydroxide | NA | Used for steam generator pH adjustment during wet lay up. |
| Morpholine | 0 - 150 ppm | Normal operating range is 0 -25 ppm. During outages, wet lay-up range is 50 – 100 ppm. |
| Aqueous Alkylamine (DAE) | 0 - 150 ppm | Normal operating range is between 0 - 25 ppm. During outages, wet lay-up range is 50 – 100 ppm. |
| Methoxypropylamine (MPA) | 0 - 150 ppm | Normal operating range is between 0 - 25 ppm. During outages, wet lay-up range is 50 – 100 ppm. |
| Hydrogen Peroxide | 3000 ppm | Biological decontamination |
| Floating Solids or Visible Foam | Trace Amounts | NA |
| Total Suspended Solids | Monthly Avg = 30 ppm<br>Daily Max = 100 ppm | Request permission to delete this requirement |
| Oil or Other Substances | No visible color film on surface of receiving waters. | NA |
| RADWASTE TREATMENT SYSTEM EFFLUENT (SD003) | | |
| PARAMETER | LIMIT | RESTRICTIONS |
| Polyquartenary Amine Coagulant | NA | 500 grams added to 5000 gallons in Waste Hold-Up Tank. Used to precipitate large particles for increased filtration efficiency. |
| Floating Solids or Visible Foam | Trace Amounts | NA |
| Total Suspended Solids | Monthly Avg = 30 ppm<br>Daily Max = 100 ppm | Request permission to delete this requirement |
| Oil or Other Substances | No visible color film on surface of receiving waters | NA |

**NPDES LIMITS**
**11/1/04**

| RADWASTE TREATMENT SYSTEM EFFLUENT (SD003) [continued] | | |
|---|---|---|
| **PARAMETER** | **LIMIT** | **RESTRICTIONS** |
| Hot Lab Sink Effluent | NA | Miscellaneous indicators, reagents, samples and expired laboratory standards. Essentially removed by ion exchangers prior to discharge. |
| Sodium Hydroxide | NA | Minor system leakage from routine operations as well as small amounts from drainage for maintenance of system components. |
| TSP Free Detergent | NA | Used for laundering, protective clothing, towels, rags, and as a cleaning preparation prior to painting. |
| Chlorine Bleach | NA | Used for laundering radioactively contaminated protective clothing, towels, and rags. |
| Radiac Wash | Miscellaneous Amounts | Used for radioactive decontamination wetting agent. |
| Hydrogen Peroxide | Miscellaneous Amounts | Addition to decrease biological oxygen demand levels. Used in laundry and as a cleaning preparation prior to painting. Also used for personnel and equipment decontamination. |
| Boron | NA | Concentration not to exceed .5-ppm ambient value at the sluice gates. |
| Nitrite based corrosion Inhibitor with additives and biocide | NA | Minor system leakage from routine operations. Essentially removed by ion exchangers prior to discharge. |
| Ethylene Glycol | NA | Minor system leakage from routine operations. |
| Potassium Chromate Potassium Dichromate Potassium hydroxide | NA | Minor system leakage from routine operations and maintenance. Laundering of reusable towels and rags contaminated with potassium chromate. Analyze the next two ADT Monitor tanks following a potassium chromate release of >20 gallons. |
| Special Respirator Cleaner Plus | NA | Used for cleaning and decontamination in the Radiation Controlled Area. |

## NPDES LIMITS

11/1/04

| REVERSE OSMOSIS EFFLUENT (DISCHARGE SD004) | | |
|---|---|---|
| **PARAMETER** | **LIMIT** | **RESTRICTIONS** |
| Clean in Place Skid (CIP)<br>Total Suspended Solids | Batch release <= 30 ppm | Sample each batch before release. Batches may be discharged to the turbine building sump, landlock or SD004, depending on the suspended solids results. Report results in the Discharge Monitoring Report. |
| Clean in Place Skid (CDI)<br>PH | >2.0 – <12.0 | Sample each batch before release. Batches may be pH adjusted and discharged to the Turbine Building Sump, landlock, or SD004. Report results in the Discharge Monitoring Report. |
| Total Reverse Osmosis Effluent Flow | | Total effluent from all processes must me summed monthly and reported in the Discharge Monitoring Report. |
| RO and Continuous de-ionizing Units (CDI) cleaning includes: hydrochloric acid, sodium hydroxide, sodium chloride, sodium percarbonate, sodium laurel sulfate | | Periodic cleaning |
| Hydrogen Peroxide | 3000 ppm | Used for biological decontamination. Discharge to landlock, TBS, or SD004. |
| Floating Solids or Visible Foam | Trace Amounts | NA |
| Oil or Other Substances | No visible color film on surface of receiving waters | NA |
| **TURBINE BUILDING SUMP OR LAND APPLICATION (UNIT 1 = DISCHARGE SD005; UNIT 2 = DISCHARGE SD006)** | | |
| **PARAMETER** | **LIMIT** | **RESTRICTIONS** |
| Cold Lab Effluent | 75 gallons per year | Miscellaneous indicators, reagents samples and expired laboratory standards. Sinks and floor drains may collect small amounts of various cleaning solutions. |
| Floating Solids or Visible Foam | Trace Amounts | NA |
| Total Suspended Solids | Monthly Avg = 30 ppm<br>Daily Max = 100 ppm | Where the background level of the natural origin is reasonably definable and normally is higher than the specified limits, the natural level may be used as the limit. May be directed to "landlock" when > limit, provided no runoff reaches surface waters. |
| Oil and Grease | Monthly Avg = 10 ppm<br>Daily Max = 15 ppm | If contaminated with oil, the sump may be directed to landlock to facilitate cleanup. |
| Oil or Other Substances | No visible color film on surface of receiving waters | If contaminated with oil, the sump may be directed to landlock to facilitate cleanup. |

## NPDES LIMITS

11/1/04

| TURBINE BUILDING SUMP OR LAND APPLICATION (UNIT 1 = DISCHARGE SD005; UNIT 2 = DISCHARGE SD006) [Continued] | | |
|---|---|---|
| PARAMETER | LIMIT | RESTRICTIONS |
| Corrosion Inhibitor with additives and biocide | NA | Minor pump leakage and triple rinsing empty drums. |
| Ethylene Glycol | NA | Minor pump leakage and triple rinsing empty drums |
| Hydrazine, Boric Acid, Morpholine, Carbohydrazide, Ammonium Hydroxide, Methoxypropylamine, Aqueous Alkylamine | Miscellaneous amounts from Steam Generator carry over, Heating Boiler and condenser draining for maintenance | Drain chemical feed tanks and triple rinse chemical drums for safety reasons to the TBS. Drain chemical feed tanks for maintenance and outages. |
| Formula 65 | Infrequent Use | Used for condenser tube leak testing. |
| Neutralizer | NA | Needed for neutralizing hydrazine, acid, and caustic spills in the turbine building sump. If safe to do so, neutralization may be done at the spill location and then flushed to the turbine building sump system. |
| Radiac wash | NA | Wetting agent used for steam cleaning. |
| Hydrogen Peroxide | NA | Used for biological decontamination. Discharge to SD001 or landlock |

| "FIRE PROTECTION SYST" - LAND APPLICATION OR TBS (UNIT 1 DISCHARGE SD005; UNIT 2 DISCHARGE SD006) | | |
|---|---|---|
| PARAMETER | LIMIT | RESTRICTIONS |
| Biocide | Per request/approval letters | Used for Zebra mussel control, with restrictions per approval letters. |

| MISCELLANEOUS PLANT BUILDING FLOOR DRAINS (DISCHARGE SD010) | | |
|---|---|---|
| PARAMETER | LIMIT | RESTRICTIONS |
| Floating Solids or Visible Foam | Trace Amounts | NA |
| Flow | 0.004 MGD | NA |
| Oil and Grease | Monthly Avg = 10 ppm<br>Daily Max = 15 ppm | NA |
| Total Suspended Solids | Monthly Avg = 30 ppm<br>Daily Max = 100 ppm | Where the background level of the natural origin is reasonably definable and normally is higher than the specified limits, the natural level may be used as the limit. |
| Oil or Other Substances | No visible color film on surface of receiving waters | NA |
| Sodium Sulfite | NA | Used on as needed basis for chlorine/bromine neutralization. |
| Hydrogen Peroxide | 3000 ppm | Used for biological decontamination. |

## NPDES LIMITS

11/1/04

| UNIT 1 AND 2 PLANT COOLING WATER OUTFALL (UNIT 1 WS001; UNIT 2 WS002) | | |
|---|---|---|
| **PARAMETER** | **LIMIT** | **RESTRICTIONS** |
| Total Residual Oxidants, Bromine/Chlorine | 2.0 ppm | Sample daily, may be obtained from Generator Hydrogen Coolers or from Cooling Water Pump Discharge if cooling water outfall lines are plugged or any point representative of system discharge. These additional sample points would be more conservative. |
| **SCREEN BACKWASH & FISH RETURN EFFLUENT (DISCHARGE 012)** | | |
| **PARAMETER** | **LIMIT** | **RESTRICTIONS** |
| Flow | 2.0 MGD | Monthly estimate. |
| Floating Solids or Visible Foam | Trace Amounts | NA |
| Screen Size | 3/8" 9/1-4/1:0.5 mm (or minimum larger sized screens) 4/1-8/31 | Commissioner approval is required to conduct a study to review the placement of 0.5 mm mesh screens or the minimum larger sized screens or other methods for the period April 1 - 15. |
| Oil or Other Substances | No visible color film on surface of receiving waters | NA |
| Debris | NA | Large debris collected at the trash racks shall be disposed of on dry land so as to prevent it from entering waters of the state. |
| **MISCELLANEOUS USE/DISPOSAL REQUESTS AND LAND APPLICATION** | | |
| **PARAMETER** | **LIMIT** | **RESTRICTIONS** |
| Cinders and corn | NA | Use for controlling leakage through stop logs while dewatering bays. Approval given for P.I. as well as other NSP facilities. |
| Chlorine | NA | Land apply for Total Coliform disinfection. |
| Soda Blast Water | NA | Land application used for transformer cleaning and other miscellaneous components. |
| Titanic C or Zyme | NA | Diluted in 300 gallons of water and used to clean intake screen panels. The screens are rinsed in the yard and the tank solution is discharged to the area of "landlock" from the turbine building. |
| Screen Rinsing | NA | Clean water ONLY for rinsing/cleaning of screens with discharge to surface waters. Green Klean is approved diluted at 5 gal to 250/300 gal water with discharge to the area of "landlock" discharge once or twice/year. |
| Bio Action Biological Drain Opener | NA | To treat outside transformer pits for stagnant rainwater. |
| Diagnostic Trasar | 0-5 ppm<br>0-6 times per year<br>Intermittent 24 hour tests | To detect and correct possible chemical leakage in various plant systems. |

# ATTACHMENT C

# SPECIAL-STATUS SPECIES CORRESPONDENCE

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NMC
Committed to Nuclear Excellence

Xcel Energy

January 25, 2008

Mr. Tony Sullins
Field Supervisor
U.S. Fish and Wildlife Service
Twin Cities Ecological Services Office
4101 East 80th Street
Bloomington, Minnesota 55425

SUBJECT: Prairie Island Nuclear Generating Plant License Renewal
Request for Information on Threatened and Endangered Species

Dear Mr. Sullins:

Nuclear Management Company (NMC), acting on behalf of Northern States Power Company, a wholly-owned subsidiary of Xcel Energy would like to thank the U.S. Fish and Wildlife Service (USFWS) for your June 20, 2007 memorandum from Mr. Gary Wege in response to our April 2007 letter seeking information and concerns about the proposed action of renewing the Prairie Island Nuclear Generating Plant (PINGP) licenses for an additional 20 years. The memorandum, listed two issues of interest to the Service: (1) potential thermal effluent changes, particularly in winter, and (2) an interagency task force's desire to draw down of Pool 3 to allow re-establishment of aquatic vegetation. The USFWS memorandum did not mention threatened and endangered species

NMC is currently finalizing the application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for Prairie Island Nuclear Generating Plant (PINGP), which expire in 2013 (Unit 1) and 2014 (Unit 2). As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened and endangered species in accordance with the Endangered Species Act" (10 CFR 51.53). The NRC will request an informal consultation with your office at a later date under Section 7 of the Endangered Species Act. By contacting you in advance, we hope to identify any issues that need to be addressed or any information your office may need to expedite the NRC consultation.

Renewal of the PINGP operating licenses would not involve any land disturbance, any changes to plant operations, or any modifications of the transmission system that connects the plant to the regional electric grid. There are plans, however, to replace the Unit 2 steam generators in the fall of 2013, one year before the Unit 2 operating license expires. The steam generators would arrive by barge, and would be installed within the Unit 2 containment structure. Temporary buildings and parking areas would be necessary, but these facilities would be constructed in previously-disturbed areas. Because, in all likelihood, Northern States Power would not replace the steam generators were it not seeking approval for an additional 20 years of operation, we have considered environmental impacts of steam generator replacement in the Environmental Report we are submitting to the NRC. In NEPA parlance, it is a "connected action" (40 CFR 1508.25). We would therefore appreciate your taking steam generator replacement into consideration when you conduct your review of the project's potential effect on threatened or endangered species.

NMC would appreciate your review of the following assessment summary, and transmittal of written concurrence, or concerns, relative to the following conclusions that continued operation of PINGP would have little or no adverse effect on threatened and endangered species in the vicinity of the site. NMC does not expect renewal of the PINGP operating license to negatively impact state or federally listed threatened and endangered species, jeopardize the continued existence of such species, or result in destruction or adverse alteration of any critical natural habitats.

Area of Concern

The PINGP site, located in Goodhue County, Minnesota, consists of 578 acres on the west bank of the Mississippi River, within the city limits of Red Wing, Minnesota (Figure 1). The City of Hastings is located approximately 13 miles northwest (upstream) of the plant. Minneapolis is located approximately 39 miles northwest and St. Paul is located approximately 32 miles northwest of the plant. At the plant location, the Mississippi River serves as the state boundary between Minnesota and Wisconsin. PINGP is located on the western shore of Sturgeon Lake, a backwater area located one mile upstream from the U.S. Army Corps of Engineers (USACE) Lock and Dam No. 3. The Vermillion River lies just west of PINGP and flows into the Mississippi River approximately two miles downstream of Lock and Dam No. 3.

Figure 2 shows the property boundary and exclusion zone, which is restricted by a perimeter fence with "No Trespassing" signs. Access to the exclusion zone by water is not restricted by a fence; however, "No Trespassing" signs are placed at intervals along the shoreline of the river. East of the plant the exclusion zone boundary extends to the main channel of the Mississippi River. Islands within this boundary as well as a small strip of land northeast of the plant are owned by the Corps of Engineers.

Directly north of Xcel property lies the Prairie Island Indian Community and Reservation, a federally recognized Indian Tribe organized under the Indian Reorganization Act. The Prairie Island Indian Community owns and operates the Treasure Island Resort and Casino, a 250-room hotel and convention center that is currently being expanded. It offers gaming, dining, live entertainment, an RV park, a 137-slip marina to accommodate visitors arriving by the Mississippi River, and sightseeing and dinner cruises on their river boat.

Five transmission lines connect PINGP to the regional electric system. The transmission system is depicted in Figures 3 and 4. The output of PINGP is delivered to the substation just north of the generating facilities with 345-kV and 161-kV switchyards, where five transmission lines leave via three transmission corridors. The transmission lines include two 2.5 mile (Red Rock 1 and Adams) transmission connections, the Red Rock 2 connection to the Red Rock Substation in St. Paul, the Blue Lake Substation connection, and the Spring Creek Substation connection.

Transmission corridors are maintained by Xcel Energy and Great River Energy using an Integrated Vegetation Management (IVM) approach that includes both mechanical and chemical control methods. In particular, both wetland and upland habitats are maintained in low-growing vegetation through the use of manual cutting and the selective application of EPA-approved herbicides resulting in the open habitats preferred by threatened and endangered species.

NMC does not expect PINGP operations through the period of extended operation (an additional 20 years) to have little or no adverse affect on threatened or endangered species in the vicinity of PINGP and associated transmission lines. Nor does NMC expect steam generator replacement to adversely impact ecological resources on site because the project will not involve ground disturbing activities in any previously undisturbed areas.

We would appreciate your sending a letter detailing any concerns you may have about potential impacts to threatened or endangered species (or their habitats) in the area of PINGP or confirming NMC's conclusion that operation of PINGP over the license renewal term would have no effect on these species. This letter serves as NMC's official request for USFWS concerns about threatened and endangered species issues regarding PINGP license renewal. NMC will include a copy of this letter and your response in the license renewal application that we submit to the NRC.

Again, thank you for your previous assistance providing PINGP with USFWS concerns. We look forward to continuing to work with the USFWS through the license renewal process. Please direct any requests for additional information, questions and your response to:

James J. Holthaus, PMP
Environmental Project Manager
Prairie Island Nuclear Generating Plant
1717 Wakonade Drive East
13 – Plex (License Renewal)
Welch, MN 55089
651-388-1121 ext 7268

Sincerely,

Mike Wadley

Mike Wadley
Prairie Island Site Vice President
Nuclear Management Company

Enclosures: Figure 1
Figure 2
Figure 3
Figure 4

Figure 1
PINGP 50-Mile Radius

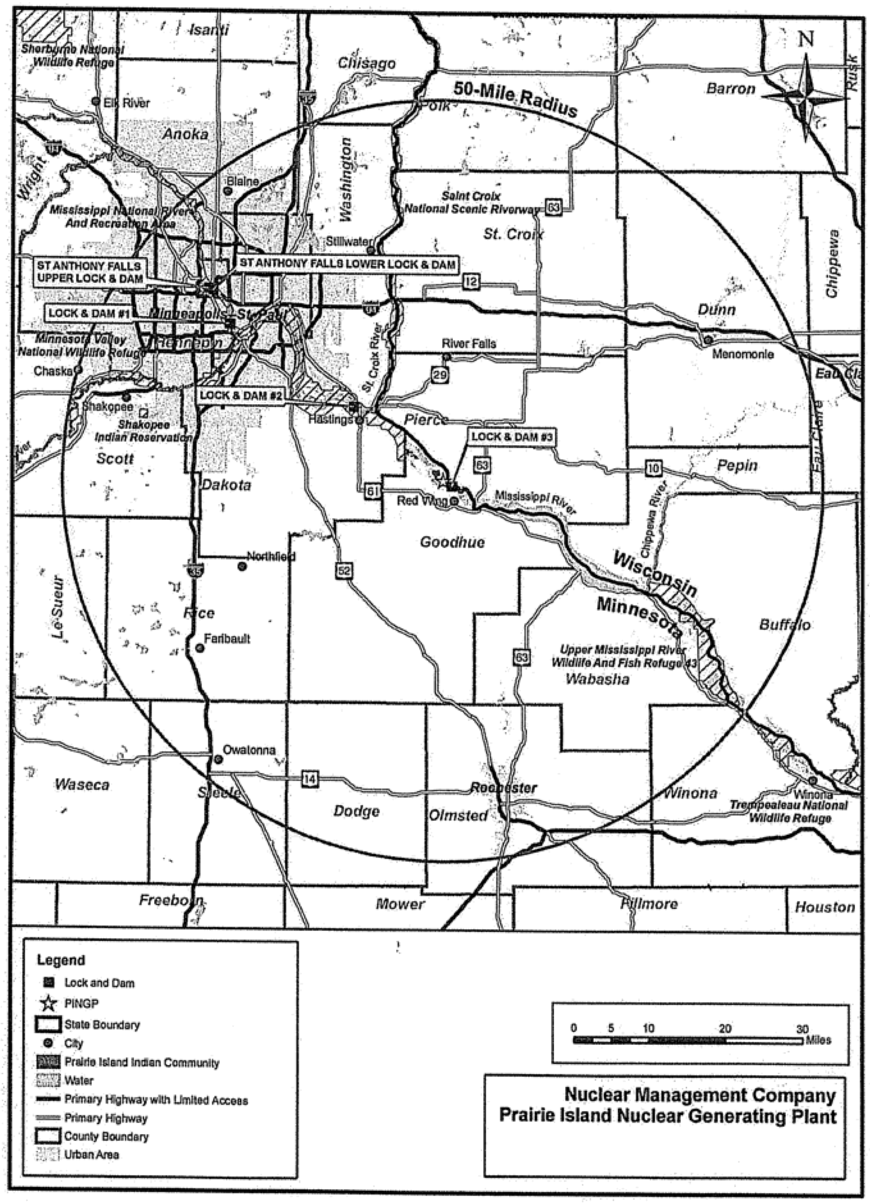


Figure 2
PINGP Site Boundary

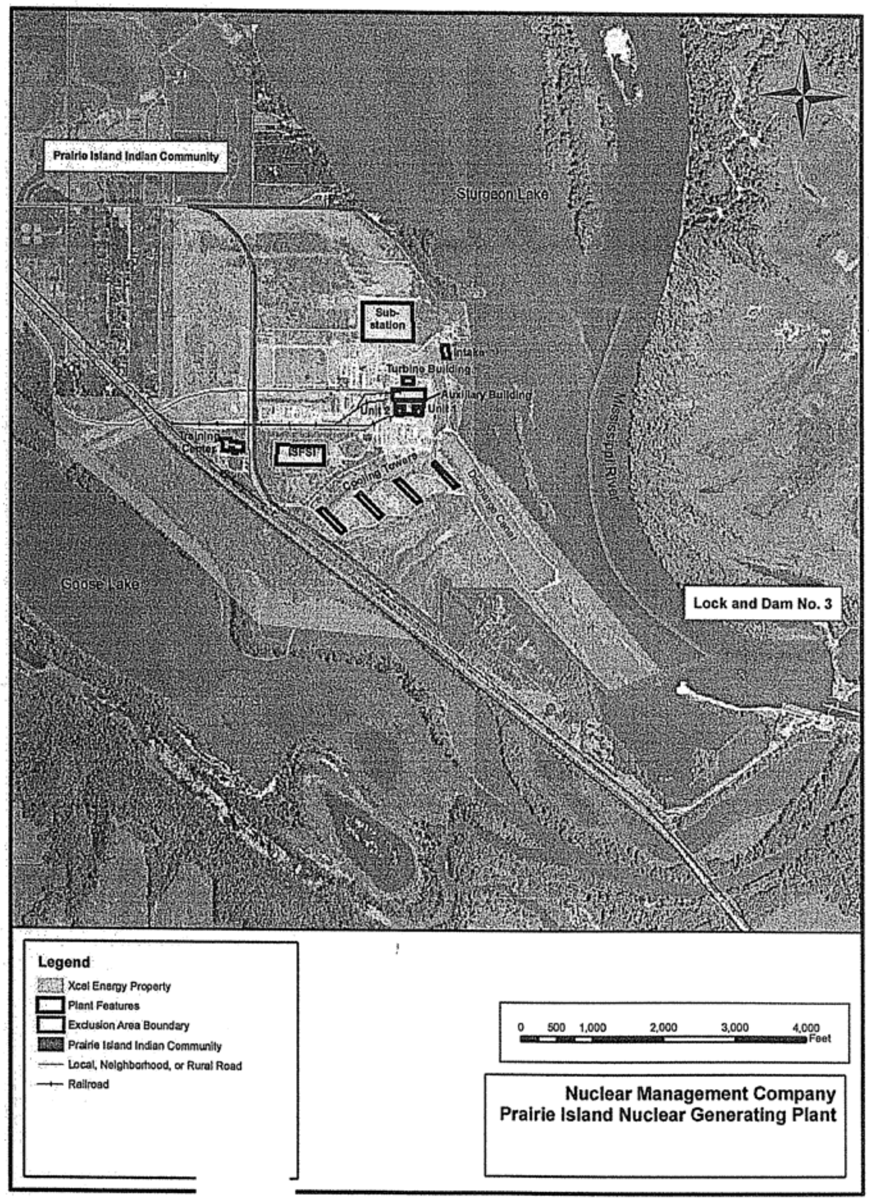


Figure 3
PINGP Site Transmission Line Layout

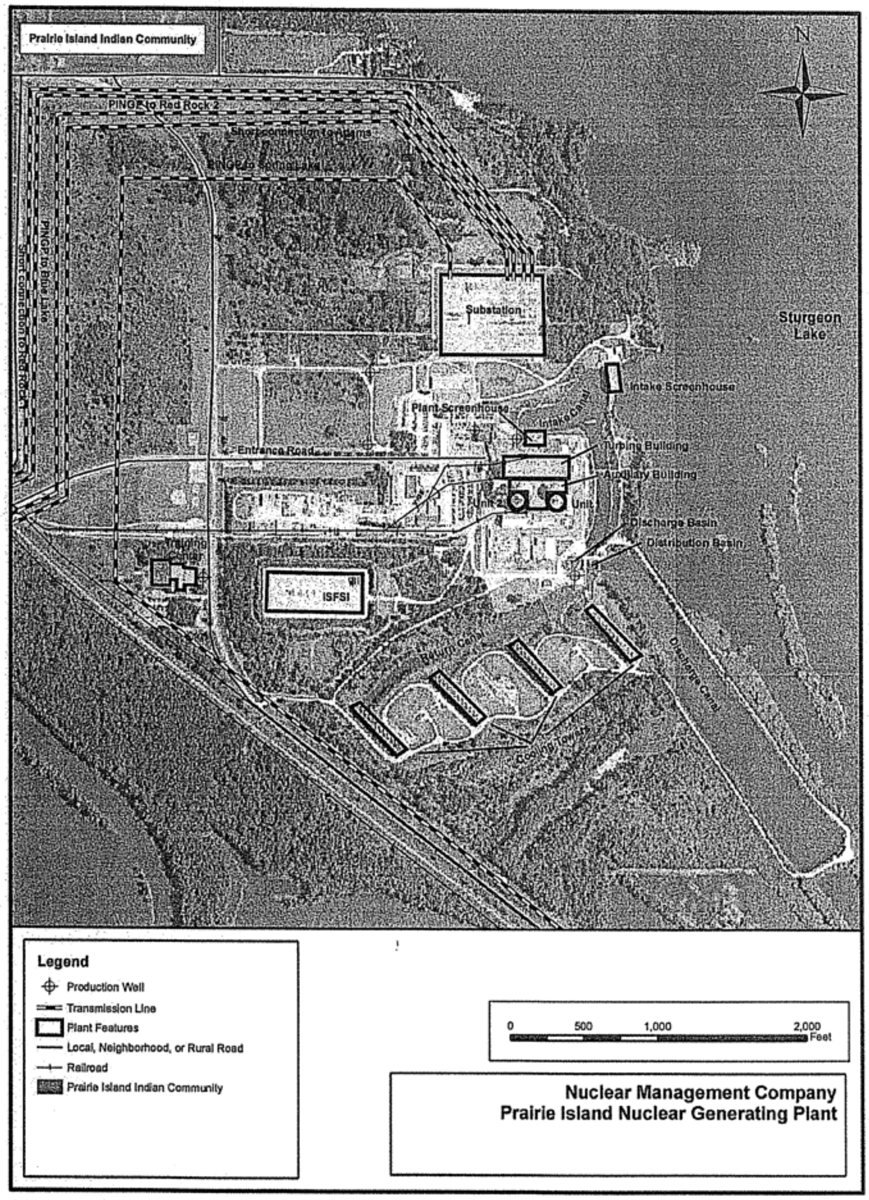
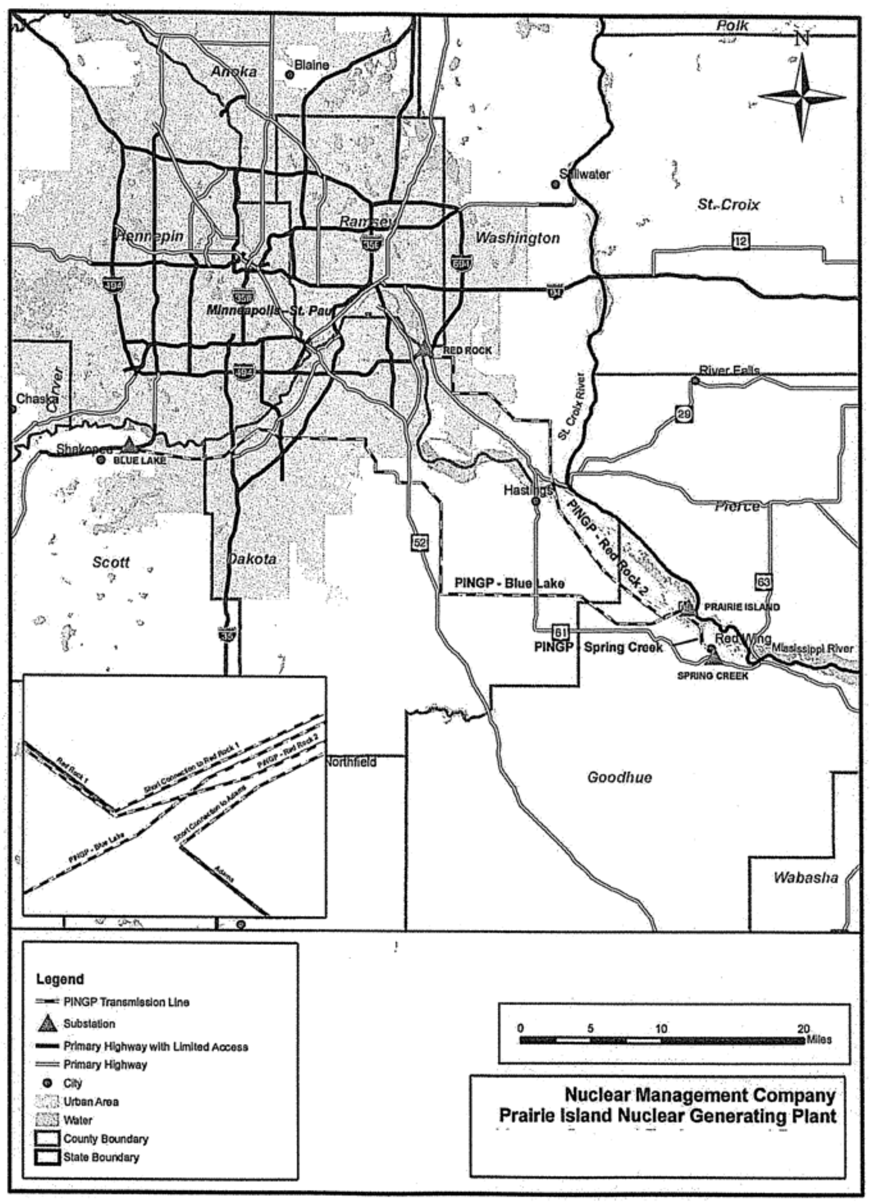


Figure 4
PINGP Transmission Outlets



lo not staple documents

| For Agency Use Only: | | |
|---|---|---|
| Received ______ | Due ______ | RUSH |
| Related ES# ______ | | |
| Search Radius ______ mi. | ER/All EOs ______ | |
| Map'd ____ C / NoC Let ____ | Inv ____ | Log out ____ |

**MINNESOTA NATURAL HERITAGE INFORMATION SYSTEM DATA REQUEST FORM**

DATE OF REQUEST 5/14/07

WHO IS REQUESTING THE INFORMATION?
Name and Title James Holthaus, Environmental Project Manager
Agency/Company Nuclear Management Company
Address 13-Plex 1717 Wakonade Dr E Welch, MN 55089
(Street) (City) (State) (Zip Code)
Phone 651-388-1121 (7268) FAX 612-330-5801 e-mail james.holthaus@nmcco.com

THIS INFORMATION IS BEING REQUESTED ON BEHALF OF (if applicable): ______

WHAT INFORMATION DO YOU NEED?
✓ Printouts of known occurrences of federally and state listed plants and animals; native plant communities; and aggregation sites such as bat hibernacula, colonial waterbird nesting sites, and prairie chicken booming grounds.
___ Information listed above, plus geological features and state rare species with no legal status.
___ Other (specify): ______

Frequent applicants: Check here if you DO NOT need a copy of the field-by-field explanation of the printouts: ____

WHERE IS THE AREA OF INTEREST? 1) ENCLOSE A MAP showing detailed boundaries of the project area (topographic maps or aerial photos are preferred). 2) If a GIS shapefile of the project area is available, please provide a copy projected in UTM Zone 15, NAD83).

For Agency Use Only: REGION

**PROVIDE THE FOLLOWING REQUIRED PROJECT INFORMATION**

| County | Twnshp# | Range# | Section(s) (and half-section, quarter-section, etc., if known) |
|---|---|---|---|
| Goodhue | T113 N | 15W | Sections 4 and 5 |
| | | | |
| | | | |
| | | | |

Project Name Prairie Island Nuclear Generating Plant (PINGP) license renewal
Project Proposer Nuclear Management Company (NMC)
Detailed Project Description (attach additional sheets if necessary) NMC proposes to renew operating licenses for PINGP Units 1 and 2. Although no land disturbance is anticipated, the US Nuclear Regulatory Commission (NRC) requires applicants for operating licenses to contact state resource agencies and request information on state- and federally listed species in the project area. The project area includes the 578-acre PINGP site and associated transmission corridors.
Past Land-Use of Project Site Prior to NMC's (then Northern States Power) acquisition of the property, most upland portions of the site were parts of family farms

(OVER)

HOW WILL THE INFORMATION BE USED? Describe the planned use of the information, including in what form and detail you wish to publish this information, if any. Information will be used to evaluate potential ecological impacts of renewing the operating licenses of PINGP Units 1 and 2. Locations of significant natural communities(e.g., colonial waterbird colonies) will not be shown on maps in the Environmental Report submitted to NRC if that is Minnesota DNR's preference.

**TURN-AROUND TIME**

**Requests generally take 3 weeks from date of receipt to process, and are processed in the order received. Rush requests are processed in 2 weeks or less.**

**FEES**

**For-profit organizations, including consultants working for governmental agencies, are charged a fee for this service. In addition, a fee may be charged for large requests from any source. A surcharge (currently $50) is applied for rush orders; if this is a rush order, please check the blank below. Fees subject to change. A fee schedule is available upon request. Please do not include payment with your request; an invoice will be sent to you.**

_X_ **Rush**

"The information supplied above is complete and accurate. I understand that material supplied to me from the Minnesota Natural Heritage Information System is copyrighted and that I am not permitted to reproduce or publish any of this copyrighted material without prior written permission from the Minnesota DNR. Further, if permission to publish is given, I understand that I must credit the Minnesota Natural Heritage and Nongame Research Program, Minnesota Department of Natural Resources as the source of the material."

Signature James Holthaus

| Mail or email completed forms to: | | For further information call: |
|---|---|---|
| Endangered Species Environmental Review Coordinator<br>Sarah.wren@dnr.state.mn.us | *(for project reviews)*<br>e.g. EAWs | (651) 259-5107 or 259-5109 |
| or<br>Assistant Database Manager<br>Sharron.nelson@dnr.state.mn.us | *(for general requests)* | (651) 259-5123 |

at
Natural Heritage and Nongame Research Program
Minnesota Department of Natural Resources
500 Lafayette Road, Box 25
St. Paul, Minnesota 55155

Or FAX completed forms to: (651) 296-1811

Additional information about the Natural Heritage & Nongame Research Program is available at http://www.dnr.state.mn.us/ecological_services/nhnrp/index.html

For Agency Use Only:

EO's requiring comment ____________________

Sources contacted  Topic  Response

______ ______ ______

______ ______ ______

______ ______ ______

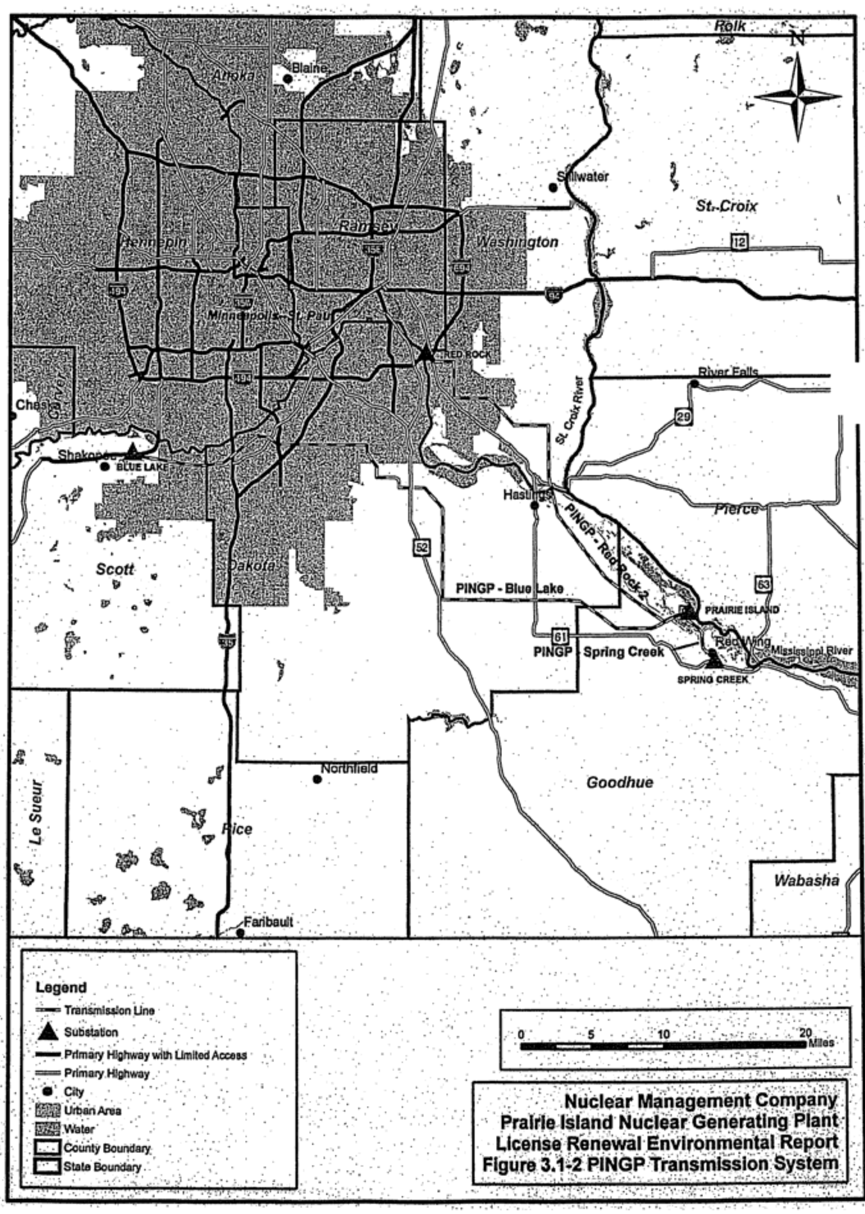
Response Summary ____________________

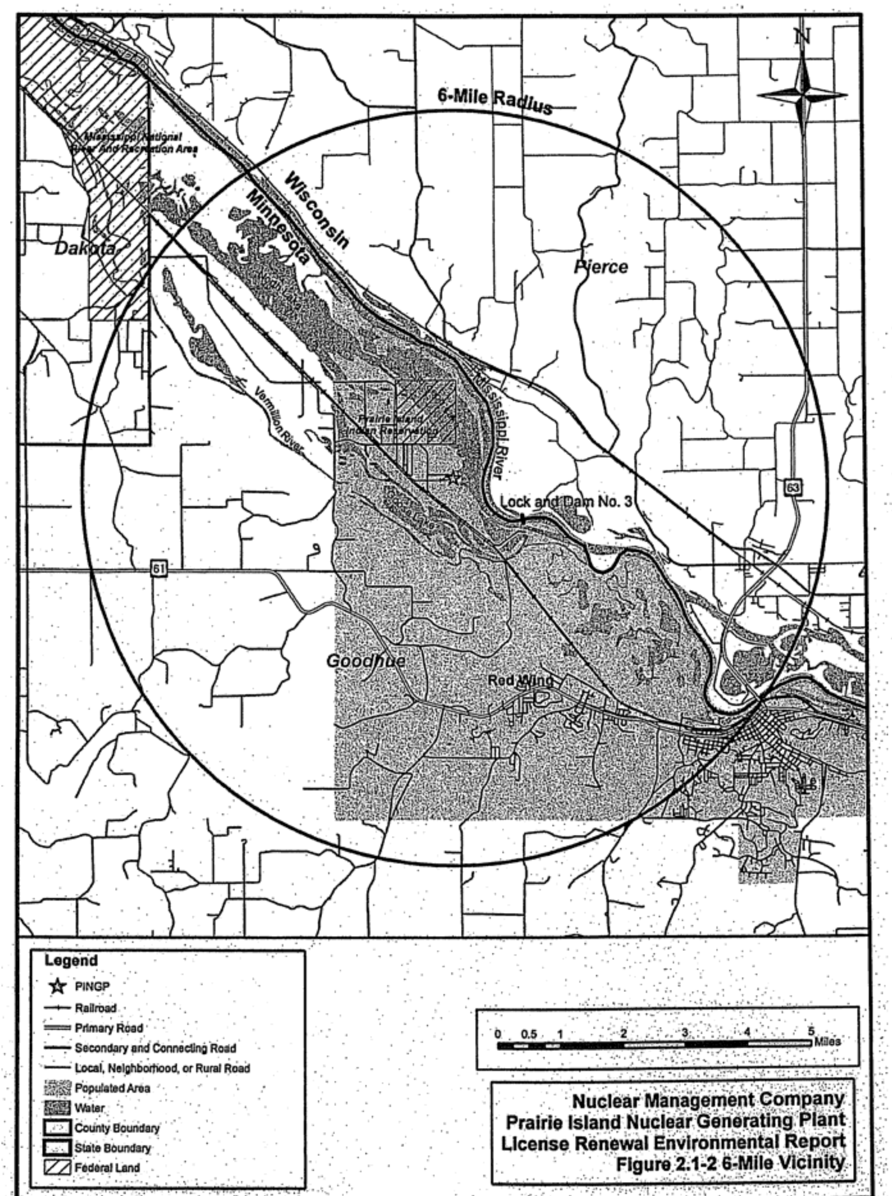
____________________

____________________

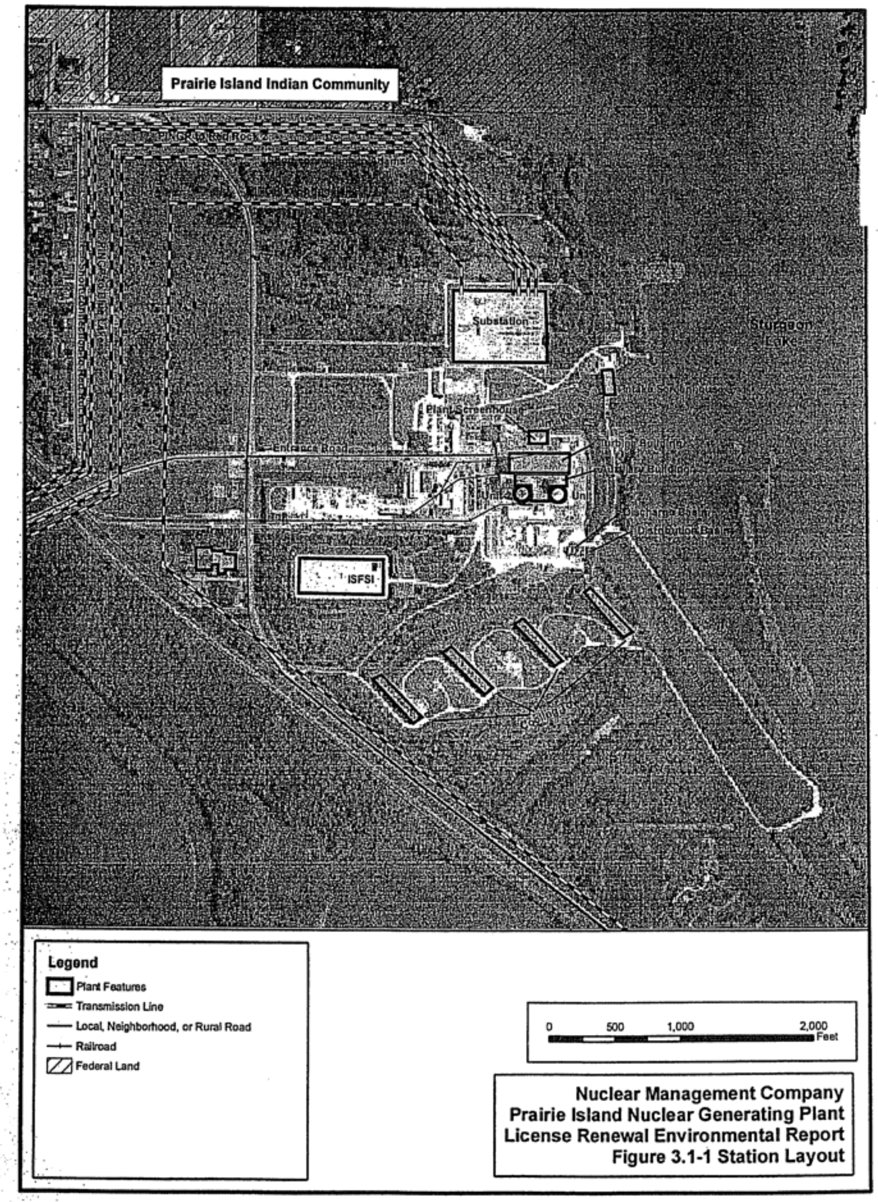
____________________ Responder ______

Revised 09/06


Polk
N
Anoka
Blaine
Stillwater
St. Croix
Ramsey
Washington
Hennepin
Minneapolis - St. Paul
RED ROCK
River Falls
St. Croix River
Shakopee
BLUE LAKE
Hastings
Pierce
PINGP - Red Rock 2
Scott
Dakota
PINGP - Blue Lake
PRAIRIE ISLAND
PINGP - Spring Creek
Red Wing
Mississippi River
SPRING CREEK
Northfield
Goodhue
Le Sueur
Rice
Wabasha
Faribault
Legend
Transmission Line
Substation
Primary Highway with Limited Access
Primary Highway
City
Urban Area
Water
County Boundary
State Boundary
0 5 10 20 Miles
Nuclear Management Company
Prairie Island Nuclear Generating Plant
License Renewal Environmental Report
Figure 3.1-2 PINGP Transmission System




Nuclear Management Company
Prairie Island Nuclear Generating Plant
License Renewal Environmental Report
Figure 2.1-2 6-Mile Vicinity




**Nuclear Management Company**
**Prairie Island Nuclear Generating Plant**
**License Renewal Environmental Report**
**Figure 3.1-1 Station Layout**

Minnesota Department of Natural Resources

Natural Heritage and Nongame Research Program, Box 25
500 Lafayette Road
St. Paul, Minnesota 55155-40__

Phone: (651) 259-5109 Fax: (651) 296-1811 E-mail: lisa.joyal@dnr.state.mn.us

June 15, 2007

Mr. James Holthaus
Nuclear Management Company
13-Plex 1717 Wakonade Dr. E.
Welch, MN 55089

Re: Request for Natural Heritage information for vicinity of proposed Prairie Island Nuclear Generating Plant (license renewal), T113N R15W Sections 4 & 5, Goodhue County
NHNRP Contact #: ERDB 20070820

Dear Mr. Holthaus,

The Minnesota Natural Heritage database has been reviewed to determine if any rare plant or animal species or other significant natural features are known to occur within an approximate one-mile radius of the area indicated on the map enclosed with your information request. Based on this review, there are 73 known occurrences of rare species or native plant communities in the area searched. For details, please see the enclosed database printouts and the explanation of selected fields.

The Natural Heritage database is maintained by the Natural Heritage and Nongame Research Program, a unit within the Division of Ecological Services, Department of Natural Resources. It is continually updated as new information becomes available, and is the most complete source of data on Minnesota's rare or otherwise significant species, native plant communities, and other natural features. Its purpose is to foster better understanding and protection of these features.

Because our information is not based on a comprehensive inventory, there may be rare or otherwise significant natural features in the state that are not represented in the database. A county-by-county survey of rare natural features is now underway, and has been completed for Goodhue County. Our information about native plant communities is, therefore, quite thorough for that county. However, because survey work for rare plants and animals is less exhaustive, and because there has not been an on-site survey of all areas of the county, ecologically significant features for which we have no records may exist on the project area.

The enclosed results of the database search are provided in two formats: short record report and long record report. To control the release of locational information, which might result in the damage or destruction of a rare element, both printout formats are copyrighted.

The short record report provides rare feature locations only to the nearest section, and may be reprinted, unaltered, in an Environmental Assessment Worksheet, municipal natural resource plan, or report compiled by your company for the project listed above. If you wish to reproduce the short record report for any other purpose, please contact me to request written permission. **The long record report includes more detailed locational information, and is for your personal use only. If you wish to reprint the long record report for any purpose, please contact me to request written permission.**

Please be aware that review by the Natural Heritage and Nongame Research Program focuses only on *rare natural features*. It does not constitute review or approval by the Department of Natural Resources as a whole. If you require further information on the environmental review process for other natural resource-related issues, you may contact your Regional Environmental Assessment Ecologist, Wayne Barstad, at (651) 772-7940.

An invoice in the amount of $85.48 will be mailed to you under separate cover within two weeks of the date of this letter. You are being billed for map and database search and staff scientist review. Thank you for consulting us on this matter, and for your interest in preserving Minnesota's rare natural resources.

Sincerely,

Lisa Joyal

Lisa A. Joyal
Endangered Species Environmental Review Coordinator

encl: Database search results
Rare Feature Database Print-Outs: An Explanation of Fields

**Minnesota Natural Heritage & Nongame Research Program**
**Short Record Report of Element Occurrences within 1 mile radius of:**
Prairie Island Nuclear Generating Plant License Renewal
T113N R15W Sections 4 & 5
Goodhue County

| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Dakota, Goodhue, Wabasha County, MN** | | | | | | |
| Polyodon spathula (Paddlefish) #2<br>Location Description: Legal description is too lengthy to fit in allotted space. | | THR | S2 | G4 | 2000-10 | 16507 |
| **Dakota, Goodhue, Washington County, MN** | | | | | | |
| Ligumia recta (Black Sandshell) #405<br>Location Description: Legal description is too lengthy to fit in allotted space. | | SPC | S3 | G5 | | 33850 |
| Obovaria olivaria (Hickorynut) #138<br>Location Description: Legal description is too lengthy to fit in allotted space. | | SPC | S3 | G4 | 2005-09-07 | 33655 |
| Polyodon spathula (Paddlefish) #1<br>Location Description: Legal description is too lengthy to fit in allotted space. | | THR | S2 | G4 | 2006-06-24 | 16529 |
| **Goodhue County, MN** | | | | | | |
| Acipenser fulvescens (Lake Sturgeon) #86<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G3G4 | 1997-10-23 | 20145 |
| Acipenser fulvescens (Lake Sturgeon) #153<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G3G4 | 2000-05-26 | 27745 |
| Acipenser fulvescens (Lake Sturgeon) #206<br>Location Description: T114N R15W S29, T114N R15W S32 | | SPC | S3 | G3G4 | 2002-09-08 | 30098 |
| Actinonaias ligamentina (Mucket) #115<br>Location Description: T113N R15W S9, T113N R15W S11, T114N R15W S30, T113N R15W S10, T113N R15W S13, T113N R15W S14, T113N R15W S12 | | THR | S2 | G5 | 2004-07-09 | 21135 |
| Actinonaias ligamentina (Mucket) #158<br>Location Description: T113N R15W S4, T113N R15W S9, T113N R15W S8, T113N R15W S5, T114N R15W S32, T114N R15W S33 | | THR | S2 | G5 | 1980-09-17 | 25515 |
| Alasmidonta marginata (Elktoe) #116<br>Location Description: T114N R15W S31, T114N R15W S30, T114N R15W S32, T113N R15W S10, T114N R15W S29 | | THR | S2 | G4 | 2004-08-02 | 31515 |
| Alosa chrysochloris (Skipjack Herring) #17<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G5 | 1993-08-23 | 6478 |
| Ammocrypta asprella (Crystal Darter) #23<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G3 | 1995-06-16 | 21031 |



Printed 6/15/2007

**Minnesota Natural Heritage & Nongame Research Program**
**Short Record Report of Element Occurrences within 1 mile radius of:**
Prairie Island Nuclear Generating Plant License Renewal
T113N R15W Sections 4 & 5
Goodhue County

| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Goodhue County, MN** | | | | | | |
| Apalone mutica (Smooth Softshell) #13<br>Location Description: T113N R15W S10 | | SPC | S3 | G5 | 1998-06-22 | 30177 |
| Apalone mutica (Smooth Softshell) #18<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G5 | 1996-06-19 | 30178 |
| Arcidens confragosus (Rock Pocketbook) #17<br>Location Description: Legal description is too lengthy to fit in allotted space. | | END | S1 | G4 | 2004-07-09 | 25720 |
| Clemmys insculpta (Wood Turtle) #22<br>Location Description: T113N R15W S16, T113N R15W S15 | | THR | S2 | G4 | 1973-06- | 1494 |
| Cycleptus elongatus (Blue Sucker) #30<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G3G4 | 1992-10-14 | 16098 |
| Cycleptus elongatus (Blue Sucker) #56<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G3G4 | 1995-09-05 | 6434 |
| Cycleptus elongatus (Blue Sucker) #82<br>Location Description: T114N R15W S29, T114N R15W S28, T114N R15W S32, T114N R15W S33 | | SPC | S3 | G3G4 | 1997-05-22 | 23206 |
| Cyclonaias tuberculata (Purple Wartyback) #34<br>Location Description: T113N R15W S14, T113N R15W S12, T113N R15W S11, T113N R15W S13, T113N R15W S10 | | THR | S2 | G5 | 2004-07-09 | 21140 |
| Dendroica cerulea (Cerulean Warbler) #40<br>Location Description: T113N R16W S1, T113N R15W S6 | | SPC | S3B | G4 | 1990-05-31 | 17191 |
| Dendroica cerulea (Cerulean Warbler) #41<br>Location Description: T113N R15W S16, T113N R15W S8, T113N R15W S9 | | SPC | S3B | G4 | 1990-07-05 | 17189 |
| Dendroica cerulea (Cerulean Warbler) #44<br>Location Description: T113N R15W S16, T113N R15W S9 | | SPC | S3B | G4 | 1996-07-05 | 16976 |
| Dendroica cerulea (Cerulean Warbler) #45<br>Location Description: T113N R15W S10 | | SPC | S3B | G4 | 1990-06-13 | 16975 |
| Dendroica cerulea (Cerulean Warbler) #47<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3B | G4 | 1990-06-13 | 16973 |
| Dry Sand - Gravel Oak Savanna (So Type #36<br>Location Description: T113N R15 | | N/A | S2 | GNR | 1992 | 14964 |



Printed 6/15/2007

**Minnesota Natural Heritage & Nongame Research Program**
**Short Record Report of Element Occurrences within 1 mile radius of:**
Prairie Island Nuclear Generating Plant License Renewal
T113N R15W Sections 4 & 5
Goodhue County

| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Goodhue County, MN** | | | | | | |
| Ellipsaria lineolata (Butterfly) #27<br>Location Description: T113N R15W S10 | | THR | S2 | G4 | 1999-07- | 26065 |
| Ellipsaria lineolata (Butterfly) #46<br>Location Description: T113N R15W S9, T113N R15W S10 | | THR | S2 | G4 | 2003-Pre | 31484 |
| Elliptio crassidens (Elephant-ear) #4<br>Location Description: Legal description is too lengthy to fit in allotted space. | | END | S1 | G5 | 1944-Pre | 21139 |
| Elliptio dilatata (Spike) #113<br>Location Description: T113N R15W S13, T113N R15W S11, T113N R15W S10 | | SPC | S3 | G5 | 2004-07-09 | 25825 |
| Elliptio dilatata (Spike) #129<br>Location Description: T113N R15W S4, T113N R15W S9, T113N R15W S8, T113N R15W S5, T114N R15W S32, T114N R15W S33 | | SPC | S3 | G5 | 1980-09-17 | 25514 |
| Elliptio dilatata (Spike) #130<br>Location Description: T113N R15W S10 | | SPC | S3 | G5 | 1999-07- | 26069 |
| Elliptio dilatata (Spike) #202<br>Location Description: T113N R15W S9, T114N R15W S30, T113N R15W S4, T113N R15W S10 | | SPC | S3 | G5 | 2000-07-PRE | 33669 |
| Emydoidea blandingii (Blanding's Turtle) #718<br>Location Description: T114N R15W S32, T113N R15W S6, T113N R15W S5, T114N R15W S31 | | THR | S2 | G4 | 1989-07- | 17731 |
| Falco peregrinus (Peregrine Falcon) #66<br>Location Description: T113N R15W S5 | No Status | THR | S2B | G4 | 2006-06-07 | 2788 |
| Fusconaia ebena (Ebonyshell) #11<br>Location Description: T113N R15W S11, T113N R15W S12, T113N R15W S13, T113N R15W S14, T113N R15W S9, T114N R15W S33, T114N R15W S29, T114N R15W S28, T113N R15W S4, T114N R15W S32, T114N R15W S30, T114N R15W S31, T113N R15W S10 | | END | S1 | G4G5 | 2004-07-PRE | 21138 |
| Haliaeetus leucocephalus (Bald Eagle) #1532<br>Location Description: T113N R15W S8 | LT,PDL | SPC | S3B,S3N | G5 | 2000 | 21811 |
| Haliaeetus leucocephalus (Bald Eagle) #1722<br>Location Description: T113N R15W S6 | LT,PDL | SPC | S3B,S3N | G5 | 2005-03-23 | 24292 |
| Haliaeetus leucocephalus (Bald Eagle) #2142<br>Location Description: T113N R15W S6 | LT,PDL | SPC | S3B,S3N | G5 | 1999 | 27180 |
| Haliaeetus leucocephalus (Bald Eagle) #2348<br>Location Description: T113N R15W S10 | LT,PDL | SPC | S3B,S3N | G5 | 2004-Pre | 31907 |



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**Minnesota Natural Heritage & Nongame Research Program**
**Short Record Report of Element Occurrences within 1 mile radius of:**
Prairie Island Nuclear Generating Plant License Renewal
T113N R15W Sections 4 & 5
Goodhue County

| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Goodhue County, MN** | | | | | | |
| Hesperia leonardus leonardus (Leonard's Skipper) #14<br>Location Description: T113N R16W S1, T113N R15W S6 | | N/A | S3 | G4T4 | 1967-09-16 | 26346 |
| Ictiobus niger (Black Buffalo) #17<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G5 | 2000-09-25 | 24744 |
| Ictiobus niger (Black Buffalo) #19<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G5 | 2002-10-09 | 30518 |
| Lampsilis higginsi (Higgins Eye) #13<br>Location Description: T113N R15W S9, T113N R15W S11, T114N R15W S30, T113N R15W S10, T113N R15W S13, T112N R13W S1, T112N R13W S12, T113N R14W S26, T113N R14W S27, T113N R15W S14, T113N R15W S12 | LE | END | S1 | G1 | 2004-07-09 | 21134 |
| Lampsilis higginsi (Higgins Eye) #28<br>Location Description: Legal description is too lengthy to fit in allotted space. | LE | END | S1 | G1 | 2004-07-08 | 31904 |
| Lampsilis higginsi (Higgins Eye) #36<br>Location Description: T113N R15W S5, T113N R15W S4, T114N R15W S32, T114N R15W S33 | LE | END | S1 | G1 | 2005-09-29 | 33180 |
| Lampsilis teres (Yellow Sandshell) #19<br>Location Description: T113N R15W S4, T114N R15W S30, T114N R16W S13, T113N R15W S10, T114N R15W S33, T114N R15W S32 | | END | S1 | G5 | 2004-08-02 | 31366 |
| Ligumia recta (Black Sandshell) #203<br>Location Description: T113N R15W S10, T113N R15W S11, T114N R15W S30 | | SPC | S3 | G5 | 2004-08-02 | 26070 |
| Megalonaias nervosa (Washboard) #13<br>Location Description: T113N R15W S10 | | THR | S2 | G5 | 2004-07-09 | 26030 |
| Megalonaias nervosa (Washboard) #19<br>Location Description: T113N R15W S9, T113N R15W S10, T114N R15W S32, T113N R15W S5, T113N R15W S4, T114N R15W S33 | | THR | S2 | G5 | 2005-09-07 | 31491 |
| Native Plant Community, Undetermined Class #856<br>Location Description: T114N R15W S31, T114N R15W S30 | | N/A | SNR | GNR | 1992-09-01 | 14790 |
| Native Plant Community, Undetermined Class #1058<br>Location Description: T113N R15W S6 | | N/A | SNR | GNR | 1992-08-19 | 14959 |
| Native Plant Community, Undetermined Class #1860<br>Location Description: T113N R15W S8, T113N R15W S7 | | N/A | SNR | GNR | 1991-09-17 | 13269 |



Printed 6/15/2007

**Minnesota Natural Heritage & Nongame Research Program**
**Short Record Report of Element Occurrences within 1 mile radius of:**
Prairie Island Nuclear Generating Plant License Renewal
T113N R15W Sections 4 & 5
Goodhue County

| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Goodhue County, MN** | | | | | | |
| Native Plant Community, Undetermined Class #1895<br>Location Description: T113N R15W S6 | | N/A | SNR | GNR | 1992-08-19 | 14958 |
| Notropis amnis (Pallid Shiner) #11<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G4 | 1949 | 16054 |
| Obovaria olivaria (Hickorynut) #78<br>Location Description: T113N R15W S10 | | SPC | S3 | G4 | 2004-07-09 | 26071 |
| Panax quinquefolius (American Ginseng) #83<br>Location Description: T113N R16W S1, T113N R15W S6 | | SPC | S3 | G3G4 | 1991-08-09 | 12945 |
| Panax quinquefolius (American Ginseng) #84<br>Location Description: T113N R15W S8, T113N R15W S7 | | SPC | S3 | G3G4 | 1991-09-17 | 12946 |
| Plethobasus cyphyus (Sheepnose) #2<br>Location Description: Legal description is too lengthy to fit in allotted space. | C | END | S1 | G3 | 1944-Pre | 21137 |
| Pleurobema coccineum (Round Pigtoe) #77<br>Location Description: T113N R15W S13, T113N R15W S10, T113N R15W S9, T113N R14W S27, T113N R14W S26 | | THR | S2 | G4 | 2004-07-09 | 26072 |
| Pleurobema coccineum (Round Pigtoe) #123<br>Location Description: T114N R16W S13, T114N R15W S30 | | THR | S2 | G4 | 2004-08-02 | 31707 |
| Quadrula metanevra (Monkeyface) #29<br>Location Description: T113N R15W S14, T113N R15W S9, T113N R15W S11, T113N R15W S10, T113N R15W S12, T113N R15W S13 | | THR | S2 | G4 | 2004-07-09 | 21136 |
| Quadrula metanevra (Monkeyface) #37<br>Location Description: T113N R15W S10 | | THR | S2 | G4 | 2000-07-20 | 26060 |
| Quadrula metanevra (Monkeyface) #62<br>Location Description: T114N R15W S30 | | THR | S2 | G4 | 2000-Pre | 31546 |
| Quadrula nodulata (Wartyback) #20<br>Location Description: T113N R15W S10 | | END | S1 | G4 | 1999-07-17 | 26073 |
| Silver Maple - (Virginia Creeper) Floodplain Forest Type #1<br>Location Description: T113N R15W S16, T113N R15W S9 | | N/A | S3 | GNR | 1990-08-08 | 11936 |
| Tritogonia verrucosa (Pistolgrip) #37<br>Location Description: T113N R15W S10 | | THR | S2 | G4G5 | 1999-07- | 26074 |



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**Minnesota Natural Heritage & Nongame Research Program**
**Short Record Report of Element Occurrences within 1 mile radius of:**
Prairie Island Nuclear Generating Plant License Renewal
T113N R15W Sections 4 & 5
Goodhue County



| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Non-MN County - Located just outside Minnesota in adjacent jurisdiction(s).** | | | | | | |
| Haliaeetus leucocephalus (Bald Eagle) #575<br>Location Description: Just outside Minnesota in adjacent jurisdiction(s). | LT,PDL | SPC | S3B,S3N | G5 | 1990 | 8201 |
| Haliaeetus leucocephalus (Bald Eagle) #984<br>Location Description: Just outside Minnesota in adjacent jurisdiction(s). | LT,PDL | SPC | S3B,S3N | G5 | 1991 | 13047 |
| Haliaeetus leucocephalus (Bald Eagle) #1125<br>Location Description: Just outside Minnesota in adjacent jurisdiction(s). | LT,PDL | SPC | S3B,S3N | G5 | 1994 | 15405 |
| Haliaeetus leucocephalus (Bald Eagle) #1264<br>Location Description: Just outside Minnesota in adjacent jurisdiction(s). | LT,PDL | SPC | S3B,S3N | G5 | 1994 | 17000 |
| Haliaeetus leucocephalus (Bald Eagle) #1524<br>Location Description: Just outside Minnesota in adjacent jurisdiction(s). | LT,PDL | SPC | S3B,S3N | G5 | 1998 | 21803 |
| Tritogonia verrucosa (Pistolgrip) #63<br>Location Description: Just outside Minnesota in adjacent jurisdiction(s). | | THR | S2 | G4G5 | 2000-Pre | 31493 |

**Records Printed = 73**



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Minnesota Department of Natural Resources

Natural Heritage and Nongame Research Program, Box 25

500 Lafayette Road

St. Paul, Minnesota 55155-4025

Phone: (651) 259-5109 Fax: (651) 296-1811 E-mail: lisa.joyal@dnr.state.mn.us

August 9, 2007

Mr. James Holthaus
Nuclear Management Company
13-Plex 1717 Wakonade Drive East
Welch, MN 55089

Re: Request for Natural Heritage information for vicinity of proposed Prairie Island Nuclear Generating Plant – **Transmission Lines** (license renewal), Scott, Dakota, Goodhue, and Washington Counties
NHNRP Contact #: ERDB 20070820-0002

Dear Mr. Holthaus,

The Minnesota Natural Heritage database has been reviewed to determine if any rare plant or animal species or other significant natural features are known to occur within an approximate one-mile radius of the area indicated on the map enclosed with your information request. Based on this review, there are 367 known occurrences of rare species or native plant communities in the area searched. For details, please see the enclosed database printouts and the explanation of selected fields.

The Natural Heritage database is maintained by the Natural Heritage and Nongame Research Program, a unit within the Division of Ecological Resources, Department of Natural Resources. It is continually updated as new information becomes available, and is the most complete source of data on Minnesota's rare or otherwise significant species, native plant communities, and other natural features. Its purpose is to foster better understanding and protection of these features.

Because our information is not based on a comprehensive inventory, there may be rare or otherwise significant natural features in the state that are not represented in the database. A county-by-county survey of rare natural features is now underway, and has been completed for Scott, Dakota, Goodhue, and Washington Counties. Our information about native plant communities is, therefore, quite thorough for those counties. However, because survey work for rare plants and animals is less exhaustive, and because there has not been an on-site survey of all areas of each county, ecologically significant features for which we have no records may exist on the project area.

The enclosed results of the database search are provided in two formats: short record report and long record report. To control the release of locational information, which might result in the damage or destruction of a rare element, both printout formats are copyrighted.

The short record report provides rare feature locations only to the nearest section, and may be reprinted, unaltered, in an Environmental Assessment Worksheet, municipal natural resource plan, or report compiled by your company for the project listed above. If you wish to reproduce the short record report for any other purpose, please contact me to request written permission. **The long record report includes more detailed locational information, and is for your personal use only. If you wish to reprint the long record report for any purpose, please contact me to request written permission.**

Please be aware that review by the Natural Heritage and Nongame Research Program focuses only on *rare natural features*. It does not constitute review or approval by the Department of Natural Resources as a whole. If you require further information on the environmental review process for other natural resource-related issues, you may contact your Regional Environmental Assessment Ecologist, Wayne Barstad, at (651) 772-7940.

An invoice in the amount of $250.55 will be mailed to you under separate cover within two weeks of the date of this letter. You are being billed for the database search and printouts. Thank you for consulting us on this matter, and for your interest in preserving Minnesota's rare natural resources.

Sincerely,

Lisa Joyal

Lisa Joyal
Endangered Species Environmental Review Coordinator

encl: Database search results
Rare Feature Database Print-Outs: An Explanation of Fields

**Minnesota Natural Heritage & Nongame Research Program**
**Short Record Report of Element Occurrences within 1 mile radius of:**
Prairie Island Nuclear Generating Plant - Transmission Lines
Multiple TRS
Scott, Dakota, Goodhue, and Washington Counties

| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Blue Earth, Brown, Carver, Chippewa, Dakota, Hennepin, Le Sueur, Nicollet, Ramsey, Redwood, Renville, Scott, Sibley, Washington, Yellow Medicine County, MN** | | | | | | |
| Polyodon spathula (Paddlefish) #4<br>Location Description: Legal description is too lengthy to fit in allotted space. | | THR | S2 | G4 | 1993-01-14 | 16501 |
| **Blue Earth, Brown, Carver, Dakota, Hennepin, Le Sueur, Nicollet, Ramsey, Scott, Sibley County, MN** | | | | | | |
| Arcidens confragosus (Rock Pocketbook) #26<br>Location Description: Legal description is too lengthy to fit in allotted space. | | END | S1 | G4 | 2006-11-PRE | 33200 |
| Lampsilis teres (Yellow Sandshell) #10<br>Location Description: Legal description is too lengthy to fit in allotted space. | | END | S1 | G5 | 1989-10-09 | 17146 |
| **Chisago, Dakota, Washington County, MN** | | | | | | |
| Pleurobema coccineum (Round Pigtoe) #106<br>Location Description: Legal description is too lengthy to fit in allotted space. | | THR | S2 | G4 | 2003-08-06 | 30010 |
| **Dakota County, MN** | | | | | | |
| Actinonaias ligamentina (Mucket) #249<br>Location Description: T28N R22W S35 | | THR | S2 | G5 | 2001-Pre | 31776 |
| Agalinis auriculata (Eared False Foxglove) #1<br>Location Description: T27N R24W S33, T27N R24W S32 | | END | S1 | G3 | 1956-10-01 | 3359 |
| Aristida tuberculosa (Sea-beach Needlegrass) #29<br>Location Description: T114N R17W S11 | | SPC | S3 | G5 | 1992-08-14 | 13916 |
| Arnoglossum plantagineum (Tuberous Indian-plantain) #35<br>Location Description: T27N R24W S26 | | THR | S2 | G4G5 | 1993-06-02 | 17558 |
| Arnoglossum plantagineum (Tuberous Indian-plantain) #47<br>Location Description: T27N R24W S27 | | THR | S2 | G4G5 | 2003-05-20 | 26812 |
| Asclepias amplexicaulis (Clasping Milkweed) #13<br>Location Description: T114N R17W S2, T114N R17W S11 | | SPC | S3 | G5 | 1988-08-26 | 10712 |
| Asclepias sullivantii (Sullivant's Milkweed) #4<br>Location Description: T27N R24W S33, T27N R24W S32 | | THR | S2 | G5 | 1945-07-25 | 3546 |
| Besseya bullii (Kitten-tails) #22<br>Location Description: T114N R17W S31 | | THR | S2 | G3 | 2005-05-17 | 3785 |



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**Minnesota Natural Heritage & Nongame Research Program**
**Short Record Report of Element Occurrences within 1 mile radius of:**
Prairie Island Nuclear Generating Plant - Transmission Lines
Multiple TRS
Scott, Dakota, Goodhue, and Washington Counties

| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Dakota County, MN** | | | | | | |
| Besseya bullii (Kitten-tails) #45<br>Location Description: T115N R17W S34 | | THR | S2 | G3 | 1987-05-18 | 11463 |
| Besseya bullii (Kitten-tails) #73<br>Location Description: T114N R16W S28, T114N R16W S33 | | THR | S2 | G3 | 1993-06-11 | 17281 |
| Besseya bullii (Kitten-tails) #85<br>Location Description: T114N R17W S1 | | THR | S2 | G3 | 1993-06-11 | 17282 |
| Besseya bullii (Kitten-tails) #94<br>Location Description: T114N R16W S6 | | THR | S2 | G3 | 1993-07-06 | 20993 |
| Buteo lineatus (Red-shouldered Hawk) #42<br>Location Description: T115N R19W S17, T115N R19W S7, T115N R19W S8, T27N R23W S36, T27N R23W S35 | | SPC | S3B,SNRN | G5 | 1988-08-27 | 10289 |
| Buteo lineatus (Red-shouldered Hawk) #107<br>Location Description: T115N R17W S26, T115N R17W S36, T115N R17W S35, T115N R17W S25 | | SPC | S3B,SNRN | G5 | 1992-07-08 | 14014 |
| Buteo lineatus (Red-shouldered Hawk) #173<br>Location Description: T115N R17W S25, T115N R17W S36 | | SPC | S3B,SNRN | G5 | 1993-06-10 | 19611 |
| Calcareous Fen (Southeastern) Type #9<br>Location Description: T27N R24W S34, T27N R24W S27 | | N/A | S1 | GNR | 1980-06- | 242 |
| Calcareous Fen (Southeastern) Type #18<br>Location Description: T27N R24W S34, T27N R24W S27 | | N/A | S1 | GNR | 1980-06- | 14373 |
| Calcareous Fen (Southeastern) Type #25<br>Location Description: T27N R23W S19, T27N R24W S24 | | N/A | S1 | GNR | 1993-07-21 | 16550 |
| Calcareous Fen (Southeastern) Type #46<br>Location Description: T27N R24W S34, T27N R24W S27 | | N/A | S1 | GNR | 2003-05-20 | 31929 |
| Carex sterilis (Sterile Sedge) #7<br>Location Description: T27N R24W S24, T27N R23W S19, T27N R23W S18 | | THR | S2 | G4 | 1994-10-13 | 4099 |
| Carex sterilis (Sterile Sedge) #11<br>Location Description: T27N R24V | | THR | S2 | G4 | 1980-06-08 | 4103 |
| Cirsium hillii (Hill's Thistle) #[illegible]<br>Location Description: T115N [illegible] T27N R24W S28, T27N R24W S34, T27N R24W S29, T27N R24W S32, T27N R24 [illegible] 5N R21W S13, T115N R21W S14, T115N R21W S12, T115N R21W S10, T115N | | SPC | S3 | G3 | 1945-07-25 | 4169 |



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**Minnesota Natural Heritage & Nongame Research Program**
**Short Record Report of Element Occurrences within 1 mile radius of:**
Prairie Island Nuclear Generating Plant - Transmission Lines
Multiple TRS
Scott, Dakota, Goodhue, and Washington Counties

| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Dakota County, MN** | | | | | | |
| Cladium mariscoides (Twig-rush) #5<br>Location Description: T27N R24W S34, T27N R24W S27 | | SPC | S3 | G5 | 1981-03-28 | 4198 |
| Colonial Waterbird Nesting Area (Colonial Waterbird Nesting Site) #189<br>Location Description: T115N R17W S25, T115N R17W S36 | | No Status | SNR | GNR | 1977 | 594 |
| Coluber constrictor (Eastern Racer) #20<br>Location Description: T114N R17W S12, T114N R17W S11 | | SPC | S3 | G5 | 1983-08- | 1569 |
| Cristatella jamesii (James' Polanisia) #1<br>Location Description: T114N R17W S2, T114N R17W S11, T114N R17W S14 | | END | S1 | G5 | 2005-07-27 | 5328 |
| Cristatella jamesii (James' Polanisia) #13<br>Location Description: T114N R16W S16 | | END | S1 | G5 | 1993-08-25 | 18036 |
| Cypripedium candidum (Small White Lady's-slipper) #20<br>Location Description: T27N R24W S34, T27N R24W S27 | | SPC | S3 | G4 | 1980-06-08 | 4302 |
| Cypripedium candidum (Small White Lady's-slipper) #21<br>Location Description: T27N R24W S34, T27N R24W S27 | | SPC | S3 | G4 | 1980-06-08 | 4303 |
| Cypripedium candidum (Small White Lady's-slipper) #23<br>Location Description: T27N R24W S34, T27N R24W S27 | | SPC | S3 | G4 | 1982-05-18 | 4305 |
| Cypripedium candidum (Small White Lady's-slipper) #218<br>Location Description: T27N R24W S26 | | SPC | S3 | G4 | 1993-06-04 | 17299 |
| Dry Barrens Prairie (Southern) Type #11<br>Location Description: T114N R17W S2 | | N/A | S2 | GNR | 1992-08-15 | 2840 |
| Dry Barrens Prairie (Southern) Type #14<br>Location Description: T114N R17W S2, T114N R17W S11 | | N/A | S2 | GNR | 1992-08-13 | 14048 |
| Dry Bedrock Bluff Prairie (Southern) Type #137<br>Location Description: T114N R16W S33 | | N/A | S3 | GNR | 1993-08-04 | 18030 |
| Dry Bedrock Bluff Prairie (Southern) Type #138<br>Location Description: T114N R16W S33, T114N R16W S28 | | N/A | S3 | GNR | 1993-08-04 | 18032 |
| Dry Bedrock Bluff Prairie (Southern) Type #139<br>Location Description: T114N R16W S33 | | N/A | S3 | GNR | 1993-08-04 | 18029 |
| Dry Bedrock Bluff Prairie (Southern) Type #140<br>Location Description: T114N R16W S29, T114N R16W S28, T114N R16W S32, T114N R16W S33 | | N/A | S3 | GNR | 1993-08-04 | 18033 |



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**Minnesota Natural Heritage & Nongame Research Program**
**Short Record Report of Element Occurrences within 1 mile radius of:**
Prairie Island Nuclear Generating Plant - Transmission Lines
Multiple TRS
Scott, Dakota, Goodhue, and Washington Counties

| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Dakota County, MN** | | | | | | |
| Dry Bedrock Bluff Prairie (Southern) Type #276<br>Location Description: T114N R17W S32, T114N R17W S31 | | N/A | S3 | GNR | 1992-09-17 | 260 |
| Dry Sand - Gravel Oak Savanna (Southern) Type #13<br>Location Description: T115N R17W S34 | | N/A | S2 | GNR | 1997-06-20 | 2832 |
| Dry Sand - Gravel Oak Savanna (Southern) Type #37<br>Location Description: T114N R16W S17, T114N R16W S20 | | N/A | S2 | GNR | 1993-08-25 | 18026 |
| Dry Sand - Gravel Prairie (Southern) Type #214<br>Location Description: T114N R16W S17, T114N R16W S16, T114N R16W S20, T114N R16W S21 | | N/A | S2 | GNR | 1993-08-25 | 18027 |
| Dry Sand - Gravel Prairie (Southern) Type #215<br>Location Description: T114N R17W S1 | | N/A | S2 | GNR | 1993-08-27 | 18012 |
| Dry Sand - Gravel Prairie (Southern) Type #216<br>Location Description: T115N R17W S36, T114N R17W S1 | | N/A | S2 | GNR | 1993-08-27 | 18011 |
| Dry Sand - Gravel Prairie (Southern) Type #223<br>Location Description: T115N R18W S18 | | N/A | S2 | GNR | 1993-08-11 | 20984 |
| Emydoidea blandingii (Blanding's Turtle) #346<br>Location Description: T27N R23W S29, T27N R23W S31, T27N R23W S30, T27N R23W S32 | | THR | S2 | G4 | 1988-04- | 8998 |
| Emydoidea blandingii (Blanding's Turtle) #474<br>Location Description: T115N R20W S7, T115N R21W S12, T115N R20W S18, T115N R21W S13, T27N R24W S34 | | THR | S2 | G4 | 1989-07-11 | 11194 |
| Emydoidea blandingii (Blanding's Turtle) #677<br>Location Description: T115N R20W S13, T115N R20W S12, T27N R23W S33, T27N R23W S34 | | THR | S2 | G4 | 1993-04-30 | 16935 |
| Eryngium yuccifolium (Rattlesnake-master) #53<br>Location Description: T114N R18W S34, T114N R18W S33 | | SPC | S3 | G5 | 1992-09-15 | 14020 |
| Falco peregrinus (Peregrine Falcon) #56<br>Location Description: T27N R24W S23 | No Status | THR | S2B | G4 | 2006-06-07 | 16125 |
| Falco peregrinus (Peregrine Falcon) #89<br>Location Description: T115N R19W S13 | No Status | THR | S2B | G4 | 2006 | 33511 |
| Haliaeetus leucocephalus (Bald Eagle) #1304<br>Location Description: T114N R16W S16 | LT,PDL | SPC | S3B,S3N | G5 | 2004 | 18789 |



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**Minnesota Natural Heritage & Nongame Research Program**
**Short Record Report of Element Occurrences within 1 mile radius of:**
Prairie Island Nuclear Generating Plant - Transmission Lines
Multiple TRS
Scott, Dakota, Goodhue, and Washington Counties

| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Dakota County, MN** | | | | | | |
| Haliaeetus leucocephalus (Bald Eagle) #2108<br>Location Description: T115N R17W S24, T115N R17W S23 | LT,PDL | SPC | S3B,S3N | G5 | 2005-05-06 | 26991 |
| Haliaeetus leucocephalus (Bald Eagle) #2487<br>Location Description: T28N R22W S26 | LT,PDL | SPC | S3B,S3N | G5 | 2005-04-20 | 33027 |
| Hudsonia tomentosa (Beach-heather) #14<br>Location Description: T114N R17W S32, T114N R17W S31, T113N R17W S6 | | SPC | S3 | G5 | 1977-06-19 | 18057 |
| Juniperus horizontalis (Creeping Juniper) #14<br>Location Description: T115N R18W S18 | | SPC | S3 | G5 | 1993-08-06 | 17548 |
| Lanius ludovicianus (Loggerhead Shrike) #86<br>Location Description: T114N R18W S25, T114N R17W S19, T114N R17W S18, T114N R18W S24 | No Status | THR | S2B | G4 | 1994-07-15 | 12338 |
| Mesic Prairie (Southern) Type #28<br>Location Description: T27N R23W S28, T27N R23W S27 | | N/A | S2 | GNR | 1994-06-18 | 2819 |
| Mesic Prairie (Southern) Type #374<br>Location Description: T27N R24W S34, T27N R24W S27 | | N/A | S2 | GNR | 2000-09-01 | 1303 |
| Mesic Prairie (Southern) Type #392<br>Location Description: T114N R18W S34, T114N R18W S33 | | N/A | S2 | GNR | 1992-08-28 | 14055 |
| Native Plant Community, Undetermined Class #84<br>Location Description: T115N R17W S26, T115N R17W S27 | | N/A | SNR | GNR | 1994-07-18 | 2851 |
| Native Plant Community, Undetermined Class #89<br>Location Description: T114N R16W S21 | | N/A | SNR | GNR | 1997-06-20 | 2841 |
| Native Plant Community, Undetermined Class #207<br>Location Description: T115N R17W S36, T115N R16W S31 | | N/A | SNR | GNR | 1993-07-09 | 20994 |
| Native Plant Community, Undetermined Class #208<br>Location Description: T115N R17W S36 | | N/A | SNR | GNR | 1993-06-27 | 20995 |
| Native Plant Community, Undetermined Class #291<br>Location Description: T115N R17W S34, T115N R17W S27 | | N/A | SNR | GNR | 1994-04-28 | 2822 |
| Native Plant Community, Undetermined Class #292<br>Location Description: T115N R17W S34 | | N/A | SNR | GNR | 1997-06-20 | 2831 |
| Native Plant Community, Undetermined Class #484<br>Location Description: T114N R18W S36 | | N/A | SNR | GNR | 1992-07-06 | 14050 |



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**Minnesota Natural Heritage & Nongame Research Program**
**Short Record Report of Element Occurrences within 1 mile radius of:**
Prairie Island Nuclear Generating Plant - Transmission Lines
Multiple TRS
Scott, Dakota, Goodhue, and Washington Counties

| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Dakota County, MN** | | | | | | |
| Native Plant Community, Undetermined Class #884<br>Location Description: T114N R17W S32, T114N R17W S31 | | N/A | SNR | GNR | 1992-09-15 | 14052 |
| Native Plant Community, Undetermined Class #1183<br>Location Description: T115N R17W S34, T115N R17W S27 | | N/A | SNR | GNR | 1994-04-28 | 2823 |
| Native Plant Community, Undetermined Class #1311<br>Location Description: T115N R17W S26, T115N R17W S34, T115N R17W S27, T115N R17W S35 | | N/A | SNR | GNR | 1993-09-22 | 8466 |
| Native Plant Community, Undetermined Class #2128<br>Location Description: T27N R24W S27 | | N/A | SNR | GNR | 1994-09-01 | 2888 |
| Native Plant Community, Undetermined Class #2133<br>Location Description: T27N R24W S24 | | N/A | SNR | GNR | 1994-10-13 | 2889 |
| Native Plant Community, Undetermined Class #2141<br>Location Description: T114N R16W S33, T114N R16W S32 | | N/A | SNR | GNR | 1993-08-13 | 18028 |
| Native Plant Community, Undetermined Class #2146<br>Location Description: T115N R17W S35 | | N/A | SNR | GNR | 1993-09-22 | 18025 |
| Native Plant Community, Undetermined Class #2154<br>Location Description: T113N R17W S6 | | N/A | SNR | GNR | 1993-08-17 | 15061 |
| Native Plant Community, Undetermined Class #2161<br>Location Description: T113N R17W S6, T113N R17W S5 | | N/A | SNR | GNR | 1993-09-17 | 18020 |
| Oenothera rhombipetala (Rhombic-petaled Evening Primrose) #7<br>Location Description: T114N R17W S2, T114N R17W S11 | | SPC | S3 | G4G5 | 1982-07-31 | 5091 |
| Orobanche fasciculata (Clustered Broomrape) #17<br>Location Description: T114N R17W S11 | | SPC | S3 | G4 | 1993-09-13 | 12060 |
| Panax quinquefolius (American Ginseng) #134<br>Location Description: T115N R17W S35 | | SPC | S3 | G3G4 | 1993-09-22 | 18039 |
| Pituophis catenifer (Gopher Snake) #86<br>Location Description: T114N R17W S12, T114N R17W S11 | | SPC | S3 | G5 | 1995-05-06 | 20800 |
| Rhynchospora capillacea (Hair-like Beak-rush) #1<br>Location Description: T27N R24W S13, T27N R23W S18, T27N R24W S24, T27N R23W S19 | | THR | S2 | G4 | 1942-08-16 | 5427 |
| Rhynchospora capillacea (Hair-like Beak-rush) #7<br>Location Description: T27N R24W S34, T27N R24W S27 | | THR | S2 | G4 | 1981-07-20 | 5433 |



Printed 8/9/2007

**Minnesota Natural Heritage & Nongame Research Program**
**Short Record Report of Element Occurrences within 1 mile radius of:**
Prairie Island Nuclear Generating Plant - Transmission Lines
Multiple TRS
Scott, Dakota, Goodhue, and Washington Counties

| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Dakota County, MN** | | | | | | |
| Scleria verticillata (Whorled Nut-rush) #1<br>Location Description: T27N R24W S13, T27N R23W S18, T27N R24W S24, T27N R23W S19 | | THR | S2 | G5 | 1941-09-19 | 5563 |
| Scleria verticillata (Whorled Nut-rush) #7<br>Location Description: T27N R24W S34, T27N R24W S27 | | THR | S2 | G5 | 1981-07-20 | 5568 |
| Silver Maple - (Virginia Creeper) Floodplain Forest Type #55<br>Location Description: T114N R16W S21, T114N R16W S16 | | N/A | S3 | GNR | 1997-06-20 | 2843 |
| Spikerush - Bur Reed Marsh (Prairie) Type #44<br>Location Description: T114N R16W S21 | | N/A | S3 | GNR | 1997-06-20 | 2842 |
| Tamarack Swamp (Southern) Type #48<br>Location Description: T27N R23W S35, T27N R23W S27, T27N R23W S26, T27N R23W S34 | | N/A | S3 | GNR | 1993-09-08 | 18049 |
| Trillium nivale (Snow Trillium) #8<br>Location Description: T115N R17W S34 | | SPC | S3 | G4 | 2007-04-22 | 5784 |
| Valeriana edulis ssp. ciliata (Valerian) #10<br>Location Description: T27N R24W S34, T27N R24W S27 | | THR | S2 | G5T3 | 2003-05-20 | 5835 |
| Valeriana edulis ssp. ciliata (Valerian) #50<br>Location Description: T27N R24W S24 | | THR | S2 | G5T3 | 1993-06-03 | 16611 |
| Valeriana edulis ssp. ciliata (Valerian) #51<br>Location Description: T27N R24W S26 | | THR | S2 | G5T3 | 1993-06-04 | 17316 |
| Valeriana edulis ssp. ciliata (Valerian) #77<br>Location Description: T115N R21W S15 | | THR | S2 | G5T3 | 1996-06-07 | 18242 |
| **Dakota, Goodhue County, MN** | | | | | | |
| Besseya bullii (Kitten-tails) #61<br>Location Description: T114N R16W S33, T113N R16W S4 | | THR | S2 | G3 | 1993-08-02 | 13005 |
| Cirsium hillii (Hill's Thistle) #34<br>Location Description: T114N R16W S33, T113N R16W S4 | | SPC | S3 | G3 | 1991-09-26 | 13118 |
| Dry Bedrock Bluff Prairie (Southern) Type #7<br>Location Description: T114N R16W S33, T113N R16W S4 | | N/A | S3 | GNR | 1991-09-26 | 13272 |
| Dry Bedrock Bluff Prairie (Southern) Type #136<br>Location Description: T114N R16W S33, T113N R16W S4 | | N/A | S3 | GNR | 1993-08-04 | 18031 |



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|---|---|---|---|---|---|---|
| **Dakota, Goodhue County, MN** | | | | | | |
| Native Plant Community, Undetermined Class #711<br>Location Description: T114N R16W S34, T114N R16W S33, T113N R16W S4, T113N R16W S3 | | N/A | SNR | GNR | 1991-09-26 | 13273 |
| **Dakota, Goodhue, Wabasha County, MN** | | | | | | |
| Polyodon spathula (Paddlefish) #2<br>Location Description: Legal description is too lengthy to fit in allotted space. | | THR | S2 | G4 | 2000-10 | 16507 |
| **Dakota, Goodhue, Washington County, MN** | | | | | | |
| Ligumia recta (Black Sandshell) #405<br>Location Description: Legal description is too lengthy to fit in allotted space. | | SPC | S3 | G5 | | 33850 |
| Obovaria olivaria (Hickorynut) #138<br>Location Description: Legal description is too lengthy to fit in allotted space. | | SPC | S3 | G4 | 2005-09-07 | 33655 |
| Polyodon spathula (Paddlefish) #1<br>Location Description: Legal description is too lengthy to fit in allotted space. | | THR | S2 | G4 | 2006-06-24 | 16529 |
| Quadrula nodulata (Wartyback) #28<br>Location Description: T115N R17W S25, T114N R16W S13, T115N R17W S21, T115N R16W S32, T26N R20W S7, T115N R17W S23, T115N R17W S24, T115N R18W S14, T26N R21W S4, T27N R22W S35, T26N R22W S2, T26N R21W S5, T26N R20W S8 | | END | S1 | G4 | 2001-08-07 | 31400 |
| **Dakota, Hennepin County, MN** | | | | | | |
| Acris crepitans (Northern Cricket Frog) #25<br>Location Description: T27N R24W S28 | | END | S1 | G5 | 2006-06-28 | 25374 |
| Actinonaias ligamentina (Mucket) #162<br>Location Description: T27N R24W S28, T27N R24W S27 | | THR | S2 | G5 | 1989-10-09 | 28558 |
| Actinonaias ligamentina (Mucket) #268<br>Location Description: T27N R24W S29, T27N R24W S22, T27N R24W S23 | | THR | S2 | G5 | 2006-11-PRE | 34176 |
| Alosa chrysochloris (Skipjack Herring) #2<br>Location Description: T27N R24W S28, T27N R24W S29, T27N R24W S33 | | SPC | S3 | G5 | 1899-07-01 | 7128 |
| Ellipsaria lineolata (Butterfly) #31<br>Location Description: T27N R24W S28, T27N R24W S27 | | THR | S2 | G4 | 1989-10-09 | 28716 |
| Ellipsaria lineolata (Butterfly) #51<br>Location Description: T27N R24W S29, T27N R24W S23, T | | THR | S2 | G4 | !006-11-PRE | 34198 |



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|---|---|---|---|---|---|---|
| **Dakota, Hennepin County, MN** | | | | | | |
| Elliptio dilatata (Spike) #134<br>Location Description: T27N R24W S28, T27N R24W S22, T27N R24W S27 | | SPC | S3 | G5 | 1989-10-09 | 28719 |
| Elliptio dilatata (Spike) #230<br>Location Description: T27N R24W S29, T27N R24W S23, T27N R24W S22 | | SPC | S3 | G5 | 2006-11-PRE | 34207 |
| Freshwater Mussel Concentration Area (Mussel Sampling Site) #140<br>Location Description: T27N R24W S28, T27N R24W S27 | | No Status | SNR | GNR | 1989-08-28 | 14980 |
| Ictiobus niger (Black Buffalo) #18<br>Location Description: T27N R24W S13, T27N R24W S24 | | SPC | S3 | G5 | 2002-09-13 | 30131 |
| Lampsilis higginsi (Higgins Eye) #18<br>Location Description: T27N R24W S28, T27N R24W S27 | LE | END | S1 | G1 | 1989-Pre | 28601 |
| Lasmigona costata (Fluted-shell) #221<br>Location Description: T27N R24W S29, T27N R24W S22, T27N R24W S23 | | SPC | S3 | G5 | 2006-11-PRE | 34236 |
| Ligumia recta (Black Sandshell) #521<br>Location Description: T27N R24W S29, T27N R24W S22, T27N R24W S23 | | SPC | S3 | G5 | 2006-11-PRE | 34248 |
| Megalonaias nervosa (Washboard) #11<br>Location Description: T27N R24W S28, T27N R24W S27 | | THR | S2 | G5 | 1989-10-09 | 28717 |
| Megalonaias nervosa (Washboard) #26<br>Location Description: T27N R24W S29, T27N R24W S13, T27N R24W S23, T27N R24W S22 | | THR | S2 | G5 | 2006-11-PRE | 34259 |
| Native Plant Community, Undetermined Class #1359<br>Location Description: T27N R24W S27, T27N R24W S22 | | N/A | SNR | GNR | 1995-06-22 | 21565 |
| Obovaria olivaria (Hickorynut) #87<br>Location Description: T27N R24W S28, T27N R24W S27 | | SPC | S3 | G4 | 1989-10-09 | 28632 |
| Obovaria olivaria (Hickorynut) #149<br>Location Description: T27N R24W S29, T27N R24W S23, T27N R24W S22 | | SPC | S3 | G4 | 2006-11-PRE | 34263 |
| Pleurobema coccineum (Round Pigtoe) #89<br>Location Description: T27N R24W S28, T27N R24W S27 | | THR | S2 | G4 | 1989-10-09 | 28556 |
| Pleurobema coccineum (Round Pigtoe) #156<br>Location Description: T27N R24W S29, T27N R24W S22, T27N R24W S23 | | THR | S2 | G4 | 2006-11-PRE | 34270 |
| Quadrula fragosa (Winged Mapleleaf) #8<br>Location Description: T27N R24W S28, T27N R24W S29, T27N R24W S22, T27N R24W S23 | LE | END | S1 | G1 | 1989-10-Pre | 28555 |



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|---|---|---|---|---|---|---|
| **Dakota, Hennepin County, MN** | | | | | | |
| Quadrula metanevra (Monkeyface) #70<br>Location Description: T27N R24W S29, T27N R24W S23, T27N R24W S22 | | THR | S2 | G4 | 2006-11-PRE | 34280 |
| Tritogonia verrucosa (Pistolgrip) #28<br>Location Description: T27N R24W S28, T27N R24W S27 | | THR | S2 | G4G5 | 1989-10-09 | 17150 |
| **Dakota, Hennepin, Ramsey, Scott County, MN** | | | | | | |
| Arcidens confragosus (Rock Pocketbook) #11<br>Location Description: T115N R21W S9, T27N R23W S5, T28N R23W S28, T28N R23W S22, T27N R24W S27, T27N R24W S28, T28N R23W S20 | | END | S1 | G4 | 2005-09-08-09 | 17106 |
| Fusconaia ebena (Ebonyshell) #8<br>Location Description: T28N R23W S22, T28N R23W S27, T27N R24W S13, T115N R21W S6, T27N R24W S28, T115N R21W S9, T27N R24W S27, T28N R23W S23, T28N R23W S28, T28N R23W S21, T27N R24W S29, T27N R24W S23, T27N R24W S22 | | END | S1 | G4G5 | 2001-07-PRE | 17119 |
| Quadrula nodulata (Wartyback) #10<br>Location Description: T28N R23W S28, T28N R23W S14, T27N R24W S27, T28N R22W S6, T28N R23W S21, T28N R23W S23, T27N R24W S28, T28N R23W S20, T115N R21W S9, T115N R21W S6, T27N R24W S22, T28N R23W S22, T27N R24W S13, T27N R24W S29, T27N R24W S23 | | END | S1 | G4 | 2002-10-11 | 17141 |
| **Dakota, Hennepin, Scott County, MN** | | | | | | |
| Elliptio crassidens (Elephant-ear) #7<br>Location Description: T27N R24W S13, T27N R24W S28, T115N R21W S9, T27N R24W S29, T27N R24W S23, T27N R24W S22 | | END | S1 | G5 | 1977-Pre | 28164 |
| **Dakota, Ramsey County, MN** | | | | | | |
| Haliaeetus leucocephalus (Bald Eagle) #2257<br>Location Description: T28N R22W S23, T28N R22W S26, T28N R22W S22 | LT,PDL | SPC | S3B,S3N | G5 | 1987 | 20460 |
| Native Plant Community, Undetermined Class #1252<br>Location Description: T28N R22W S23, T28N R22W S15, T28N R22W S14, T28N R22W S22 | | N/A | SNR | GNR | 1975 | 1091 |
| **Dakota, Scott County, MN** | | | | | | |
| Cygnus buccinator (Trumpeter Swan) #82<br>Location Description: T114N R22W S13, T114N R22W S12, T114N R22W S11, T27N R23W S32, T27N R23W S30, T27N R23W S29, T27N R23W S31 | | THR | S2B | G4 | 2007-05-10 | 34181 |



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|---|---|---|---|---|---|---|
| **Dakota, Scott County, MN** | | | | | | |
| Emydoidea blandingii (Blanding's Turtle) #228<br>Location Description: T27N R24W S32, T115N R21W S10, T115N R21W S15, T27N R24W S31, T115N R21W S16 | | THR | S2 | G4 | 1997-06- | 7396 |
| **Dakota, Washington County, MN** | | | | | | |
| Acipenser fulvescens (Lake Sturgeon) #95<br>Location Description: T115N R17W S24, T26N R20W S9 | | SPC | S3 | G3G4 | 1993-04- | 20804 |
| Actinonaias ligamentina (Mucket) #118<br>Location Description: T26N R20W S9, T26N R20W S4, T26N R20W S7, T115N R17W S24, T115N R17W S22, T115N R17W S21, T115N R17W S25, T27N R20W S14 | | THR | S2 | G5 | 2001-09-18 | 22053 |
| Alasmidonta marginata (Elktoe) #115<br>Location Description: T115N R17W S22, T115N R17W S21, T26N R20W S7, T26N R20W S8 | | THR | S2 | G4 | 2000-Pre | 31514 |
| Arcidens confragosus (Rock Pocketbook) #22<br>Location Description: T115N R17W S23, T26N R20W S8, T26N R20W S7, T115N R17W S21, T115N R17W S22 | | END | S1 | G4 | 2002-06-19 | 31346 |
| Cycleptus elongatus (Blue Sucker) #53<br>Location Description: T28N R22W S26, T28N R22W S35 | | SPC | S3 | G3G4 | 1996-09-30 | 21476 |
| Cycleptus elongatus (Blue Sucker) #65<br>Location Description: T26N R20W S8, T115N R17W S22, T115N R17W S23 | | SPC | S3 | G3G4 | 1996-08-27 | 6427 |
| Cycleptus elongatus (Blue Sucker) #68<br>Location Description: T28N R22W S26 | | SPC | S3 | G3G4 | 1996-09-30 | 6424 |
| Cyclonaias tuberculata (Purple Wartyback) #36<br>Location Description: T115N R17W S24, T26N R20W S9 | | THR | S2 | G5 | 1988 | 16548 |
| Ellipsaria lineolata (Butterfly) #18<br>Location Description: T115N R17W S25, T115N R17W S23, T115N R17W S22, T26N R20W S7, T26N R20W S8, T26N R20W S9, T115N R17W S24 | | THR | S2 | G4 | 2002-09-26 | 16545 |
| Elliptio crassidens (Elephant-ear) #5<br>Location Description: T115N R17W S23, T115N R17W S21, T115N R17W S22, T26N R20W S8, T26N R20W S7, T26N R21W S5, T26N R21W S6, T27N R21W S32, T26N R20W S9, T115N R17W S24 | | END | S1 | G5 | 2004-08-04 | 16547 |
| Elliptio dilatata (Spike) #60<br>Location Description: T115N R17W S24, T26N R20W S9 | | SPC | S3 | G5 | 1995-08- | 16546 |



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|---|---|---|---|---|---|---|
| **Dakota, Washington County, MN** | | | | | | |
| Elliptio dilatata (Spike) #203<br>Location Description: Legal description is too lengthy to fit in allotted space. | | SPC | S3 | G5 | 2003-08-06 | 33670 |
| Epioblasma triquetra (Snuffbox) #21<br>Location Description: T115N R17W S22, T115N R17W S21, T26N R20W S7, T26N R20W S8 | | THR | S2 | G3 | 2002-Pre | 31486 |
| Falco peregrinus (Peregrine Falcon) #74<br>Location Description: T26N R20W S7, T115N R17W S22, T115N R17W S28, T115N R17W S27, T115N R17W S21 | No Status | THR | S2B | G4 | 2006 | 26781 |
| Falco peregrinus (Peregrine Falcon) #77<br>Location Description: T28N R22W S26 | No Status | THR | S2B | G4 | 2006-06-09 | 26815 |
| Fusconaia ebena (Ebonyshell) #12<br>Location Description: T115N R17W S24, T26N R20W S9, T26N R20W S8, T115N R17W S25, T115N R16W S32, T26N R20W S7, T26N R21W S12, T115N R17W S22, T115N R17W S21, T115N R17W S23 | | END | S1 | G4G5 | 2004-08-04 | 16544 |
| Fusconaia ebena (Ebonyshell) #32<br>Location Description: T28N R22W S35 | | END | S1 | G4G5 | 2001-07-PRE | 31386 |
| Haliaeetus leucocephalus (Bald Eagle) #2232<br>Location Description: T28N R22W S35 | LT,PDL | SPC | S3B,S3N | G5 | 2005-04-19 | 29876 |
| Lampsilis higginsi (Higgins Eye) #2<br>Location Description: Legal description is too lengthy to fit in allotted space. | LE | END | S1 | G1 | 2005-04-11 | 2483 |
| Lampsilis higginsi (Higgins Eye) #33<br>Location Description: T115N R17W S22, T26N R20W S8, T115N R17W S17, T115N R17W S16 | LE | END | S1 | G1 | 2005-06-23 | 33161 |
| Lanius ludovicianus (Loggerhead Shrike) #21<br>Location Description: Legal description is too lengthy to fit in allotted space. | No Status | THR | S2B | G4 | 2007-04-15 | 6734 |
| Ligumia recta (Black Sandshell) #132<br>Location Description: T115N R17W S24, T26N R20W S9, T26N R20W S8, T115N R17W S22 | | SPC | S3 | G5 | 2004-08-04 | 17539 |
| Megalonaias nervosa (Washboard) #1<br>Location Description: T115N R17W S25, T115N R17W S23, T115N R17W S22, T26N R20W S8, T26N R20W S9, T115N R17W S24 | | THR | S2 | G5 | 2003-08-06 | 16543 |
| Notropis amnis (Pallid Shiner) #17<br>Location Description: T115N R17W S24, T26N R20W S9 | | SPC | S3 | G4 | 1926-08-19 | 16060 |



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|---|---|---|---|---|---|---|
| **Dakota, Washington County, MN** | | | | | | |
| Obovaria olivaria (Hickorynut) #38<br>Location Description: T115N R17W S24, T26N R20W S9, T26N R20W S7, T26N R20W S8, T115N R17W S22 | | SPC | S3 | G4 | 2004-08-03 | 16542 |
| Plethobasus cyphyus (Sheepnose) #3<br>Location Description: T26N R20W S9, T26N R20W S8, T26N R20W S7, T26N R21W S12, T115N R17W S23, T115N R17W S21, T115N R17W S22, T115N R17W S24 | C | END | S1 | G3 | 1988-11 | 16541 |
| Plethobasus cyphyus (Sheepnose) #9<br>Location Description: T28N R22W S35 | C | END | S1 | G3 | 2001-Pre | 31380 |
| Pleurobema coccineum (Round Pigtoe) #55<br>Location Description: T115N R17W S24, T26N R20W S9 | | THR | S2 | G4 | 2004-08-03 | 16540 |
| Quadrula fragosa (Winged Mapleleaf) #17<br>Location Description: T115N R17W S22, T115N R17W S21, T26N R20W S7, T26N R20W S8 | LE | END | S1 | G1 | 2002-Pre | 31384 |
| Quadrula metanevra (Monkeyface) #30<br>Location Description: T26N R20W S9, T26N R20W S8, T115N R17W S21, T115N R16W S32, T26N R21W S12, T115N R17W S22, T115N R17W S24, T26N R20W S7, T115N R17W S25 | | THR | S2 | G4 | 2004-08-04 | 16539 |
| Quadrula nodulata (Wartyback) #22<br>Location Description: Legal description is too lengthy to fit in allotted space. | | END | S1 | G4 | 2003-08-13 | 25971 |
| Silver Maple - (Virginia Creeper) Floodplain Forest Type #14<br>Location Description: T115N R17W S23, T26N R20W S8, T115N R17W S22 | | N/A | S3 | GNR | 1987-07-08 | 7494 |
| Silver Maple - (Virginia Creeper) Floodplain Forest Type #32<br>Location Description: T27N R22W S2, T28N R22W S35 | | N/A | S3 | GNR | 1994-08-09 | 21002 |
| Silver Maple - (Virginia Creeper) Floodplain Forest Type #53<br>Location Description: T26N R20W S9, T115N R17W S25, T115N R17W S24 | | N/A | S3 | GNR | 1994-08-26 | 2852 |
| Tritogonia verrucosa (Pistolgrip) #34<br>Location Description: T115N R17W S24, T115N R17W S22, T115N R17W S21, T26N R20W S7, T26N R20W S8, T26N R20W S9 | | THR | S2 | G4G5 | 1988-11- | 16184 |
| **Goodhue County, MN** | | | | | | |
| Acipenser fulvescens (Lake Sturgeon) #86<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G3G4 | 1997-10-23 | 20145 |
| Acipenser fulvescens (Lake Sturgeon) #153<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G3G4 | 2000-05-26 | 27745 |



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|---|---|---|---|---|---|---|
| **Goodhue County, MN** | | | | | | |
| Acipenser fulvescens (Lake Sturgeon) #206<br>Location Description: T114N R15W S29, T114N R15W S32 | | SPC | S3 | G3G4 | 2002-09-08 | 30098 |
| Actinonaias ligamentina (Mucket) #115<br>Location Description: T113N R15W S9, T113N R15W S11, T114N R15W S30, T113N R15W S10, T113N R15W S13, T113N R15W S14, T113N R15W S12 | | THR | S2 | G5 | 2004-07-09 | 21135 |
| Actinonaias ligamentina (Mucket) #158<br>Location Description: T113N R15W S4, T113N R15W S9, T113N R15W S8, T113N R15W S5, T114N R15W S32, T114N R15W S33 | | THR | S2 | G5 | 1980-09-17 | 25515 |
| Alasmidonta marginata (Elktoe) #77<br>Location Description: Legal description is too lengthy to fit in allotted space. | | THR | S2 | G4 | 2004-07-09 | 26244 |
| Alasmidonta marginata (Elktoe) #116<br>Location Description: T114N R15W S31, T114N R15W S30, T114N R15W S32, T113N R15W S10, T114N R15W S29 | | THR | S2 | G4 | 2004-08-02 | 31515 |
| Alosa chrysochloris (Skipjack Herring) #17<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G5 | 1993-08-23 | 6478 |
| Ammocrypta asprella (Crystal Darter) #23<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G3 | 1995-06-16 | 21031 |
| Apalone mutica (Smooth Softshell) #13<br>Location Description: T113N R15W S10 | | SPC | S3 | G5 | 1998-06-22 | 30177 |
| Apalone mutica (Smooth Softshell) #18<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G5 | 1996-06-19 | 30178 |
| Arcidens confragosus (Rock Pocketbook) #17<br>Location Description: Legal description is too lengthy to fit in allotted space. | | END | S1 | G4 | 2004-07-09 | 25720 |
| Besseya bullii (Kitten-tails) #107<br>Location Description: T113N R15W S27 | | THR | S2 | G3 | 1997-12-08 | 22946 |
| Buteo lineatus (Red-shouldered Hawk) #52<br>Location Description: T113N R15W S22 | | SPC | S3B,SNRN | G5 | 1990-06-13 | 11415 |
| Buteo lineatus (Red-shouldered Hawk) #53<br>Location Description: T113N R15W S22, T113N R15W S21 | | SPC | S3B,SNRN | G5 | 1990-06-13 | 11414 |
| Buteo lineatus (Red-shouldered Hawk) #181<br>Location Description: T113N R15W S21 | | SPC | S3B,SNRN | G5 | 1995-05-18 | 20803 |



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|---|---|---|---|---|---|---|
| **Goodhue County, MN** | | | | | | |
| Calcareous Fen (Southeastern) Type #21<br>Location Description: T113N R15W S21, T113N R15W S28 | | N/A | S1 | GNR | 1992-06- | 14378 |
| Clemmys insculpta (Wood Turtle) #7<br>Location Description: T113N R15W S22, T113N R15W S21 | | THR | S2 | G4 | 1988-06-16 | 1480 |
| Clemmys insculpta (Wood Turtle) #22<br>Location Description: T113N R15W S16, T113N R15W S15 | | THR | S2 | G4 | 1973-06- | 1494 |
| Clemmys insculpta (Wood Turtle) #26<br>Location Description: T113N R15W S21, T113N R15W S20 | | THR | S2 | G4 | 1973-06 | 1498 |
| Clemmys insculpta (Wood Turtle) #27<br>Location Description: T113N R15W S21, T113N R15W S28 | | THR | S2 | G4 | 1988-06-09 | 1499 |
| Crotalus horridus (Timber Rattlesnake) #178<br>Location Description: T113N R16W S1, T113N R15W S21, T113N R15W S16, T113N R15W S20 | | THR | S2 | G4 | 2005-05-08 | 33383 |
| Cycleptus elongatus (Blue Sucker) #30<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G3G4 | 1992-10-14 | 16098 |
| Cycleptus elongatus (Blue Sucker) #56<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G3G4 | 1995-09-05 | 6434 |
| Cycleptus elongatus (Blue Sucker) #82<br>Location Description: T114N R15W S29, T114N R15W S28, T114N R15W S32, T114N R15W S33 | | SPC | S3 | G3G4 | 1997-05-22 | 23206 |
| Cyclonaias tuberculata (Purple Wartyback) #34<br>Location Description: T113N R15W S14, T113N R15W S12, T113N R15W S11, T113N R15W S13, T113N R15W S10 | | THR | S2 | G5 | 2004-07-09 | 21140 |
| Dendroica cerulea (Cerulean Warbler) #40<br>Location Description: T113N R16W S1, T113N R15W S6 | | SPC | S3B | G4 | 1990-05-31 | 17191 |
| Dendroica cerulea (Cerulean Warbler) #41<br>Location Description: T113N R15W S16, T113N R15W S8, T113N R15W S9 | | SPC | S3B | G4 | 1990-07-05 | 17189 |
| Dendroica cerulea (Cerulean Warbler) #43<br>Location Description: T113N R15W S21, T113N R15W S20 | | SPC | S3B | G4 | 1990-06-13 | 16977 |
| Dendroica cerulea (Cerulean Warbler) #44<br>Location Description: T113N R15W S16, T113N R15W S9 | | SPC | S3B | G4 | 1996-07-05 | 16976 |



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|---|---|---|---|---|---|---|
| **Goodhue County, MN** | | | | | | |
| Dendroica cerulea (Cerulean Warbler) #45<br>Location Description: T113N R15W S10 | | SPC | S3B | G4 | 1990-06-13 | 16975 |
| Dendroica cerulea (Cerulean Warbler) #47<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3B | G4 | 1990-06-13 | 16973 |
| Dendroica cerulea (Cerulean Warbler) #48<br>Location Description: T113N R15W S22, T113N R15W S14, T113N R15W S23, T113N R15W S15 | | SPC | S3B | G4 | 1990-06-13 | 16972 |
| Dry Bedrock Bluff Prairie (Southern) Type #100<br>Location Description: T113N R16W S9, T113N R16W S4 | | N/A | S3 | GNR | 1990-10-10 | 11771 |
| Dry Sand - Gravel Oak Savanna (Southern) Type #28<br>Location Description: T114N R16W S27, T114N R16W S23, T114N R16W S26 | | N/A | S2 | GNR | 1990-10-04 | 15932 |
| Dry Sand - Gravel Oak Savanna (Southern) Type #29<br>Location Description: T114N R16W S36 | | N/A | S2 | GNR | 1990-10-04 | 15933 |
| Dry Sand - Gravel Oak Savanna (Southern) Type #36<br>Location Description: T113N R15W S5 | | N/A | S2 | GNR | 1992 | 14964 |
| Dry Sand - Gravel Prairie (Southern) Type #167<br>Location Description: T113N R15W S22, T113N R15W S28, T113N R15W S27, T113N R15W S21 | | N/A | S2 | GNR | 1991-10-14 | 13107 |
| Dry Sand - Gravel Prairie (Southern) Type #177<br>Location Description: T113N R15W S21, T113N R15W S28 | | N/A | S2 | GNR | 1992 | 15302 |
| Ellipsaria lineolata (Butterfly) #27<br>Location Description: T113N R15W S10 | | THR | S2 | G4 | 1999-07- | 26065 |
| Ellipsaria lineolata (Butterfly) #46<br>Location Description: T113N R15W S9, T113N R15W S10 | | THR | S2 | G4 | 2003-Pre | 31484 |
| Elliptio crassidens (Elephant-ear) #4<br>Location Description: Legal description is too lengthy to fit in allotted space. | | END | S1 | G5 | 1944-Pre | 21139 |
| Elliptio dilatata (Spike) #113<br>Location Description: T113N R15W S13, T113N R15W S11, T113N R15W S10 | | SPC | S3 | G5 | 2004-07-09 | 25825 |
| Elliptio dilatata (Spike) #129<br>Location Description: T113N R15W S4, T113N R15W S9, T113N R15W S8, T113N R15W S5, T114N R15W S32, T114N R15W S33 | | SPC | S3 | G5 | 1980-09-17 | 25514 |



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|---|---|---|---|---|---|---|
| **Goodhue County, MN** | | | | | | |
| Elliptio dilatata (Spike) #130<br>Location Description: T113N R15W S10 | | SPC | S3 | G5 | 1999-07- | 26069 |
| Elliptio dilatata (Spike) #202<br>Location Description: T113N R15W S9, T114N R15W S30, T113N R15W S4, T113N R15W S10 | | SPC | S3 | G5 | 2000-07-PRE | 33669 |
| Emydoidea blandingii (Blanding's Turtle) #718<br>Location Description: T114N R15W S32, T113N R15W S6, T113N R15W S5, T114N R15W S31 | | THR | S2 | G4 | 1989-07- | 17731 |
| Emydoidea blandingii (Blanding's Turtle) #811<br>Location Description: T113N R15W S22, T113N R15W S28, T113N R15W S27, T113N R15W S21 | | THR | S2 | G4 | 1996-06-19 | 23266 |
| Falco peregrinus (Peregrine Falcon) #66<br>Location Description: T113N R15W S5 | No Status | THR | S2B | G4 | 2006-06-07 | 2788 |
| Fusconaia ebena (Ebonyshell) #11<br>Location Description: T113N R15W S11, T113N R15W S12, T113N R15W S13, T113N R15W S14, T113N R15W S9, T114N R15W S33, T114N R15W S29, T114N R15W S28, T113N R15W S4, T114N R15W S32, T114N R15W S30, T114N R15W S31, T113N R15W S10 | | END | S1 | G4G5 | 2004-07-PRE | 21138 |
| Haliaeetus leucocephalus (Bald Eagle) #1124<br>Location Description: T114N R16W S34, T114N R16W S26, T114N R16W S35, T114N R16W S27 | LT,PDL | SPC | S3B,S3N | G5 | 1996 | 15403 |
| Haliaeetus leucocephalus (Bald Eagle) #1532<br>Location Description: T113N R15W S8 | LT,PDL | SPC | S3B,S3N | G5 | 2000 | 21811 |
| Haliaeetus leucocephalus (Bald Eagle) #1705<br>Location Description: T114N R16W S27 | LT,PDL | SPC | S3B,S3N | G5 | 1998 | 23270 |
| Haliaeetus leucocephalus (Bald Eagle) #1722<br>Location Description: T113N R15W S6 | LT,PDL | SPC | S3B,S3N | G5 | 2005-03-23 | 24292 |
| Haliaeetus leucocephalus (Bald Eagle) #2142<br>Location Description: T113N R15W S6 | LT,PDL | SPC | S3B,S3N | G5 | 1999 | 27180 |
| Haliaeetus leucocephalus (Bald Eagle) #2165<br>Location Description: T113N R15W S15 | LT,PDL | SPC | S3B,S3N | G5 | 2001-Pre | 28523 |
| Haliaeetus leucocephalus (Bald Eagle) #2167<br>Location Description: T114N R16W S27 | LT,PDL | SPC | S3B,S3N | G5 | 2005-04-20 | 28572 |
| Haliaeetus leucocephalus (Bald Eagle) #2335<br>Location Description: T113N R15W S23 | LT,PDL | SPC | S3B,S3N | G5 | 2004-03-27 | 31864 |



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|---|---|---|---|---|---|---|
| **Goodhue County, MN** | | | | | | |
| Haliaeetus leucocephalus (Bald Eagle) #2348<br>Location Description: T113N R15W S10 | LT,PDL | SPC | S3B,S3N | G5 | 2004-Pre | 31907 |
| Hesperia leonardus leonardus (Leonard's Skipper) #14<br>Location Description: T113N R16W S1, T113N R15W S6 | | N/A | S3 | G4T4 | 1967-09-16 | 26346 |
| Ictiobus niger (Black Buffalo) #17<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G5 | 2000-09-25 | 24744 |
| Ictiobus niger (Black Buffalo) #19<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G5 | 2002-10-09 | 30518 |
| Lampsilis higginsi (Higgins Eye) #13<br>Location Description: T113N R15W S9, T113N R15W S11, T114N R15W S30, T113N R15W S10, T113N R15W S13, T112N R13W S1, T112N R13W S12, T113N R14W S26, T113N R14W S27, T113N R15W S14, T113N R15W S12 | LE | END | S1 | G1 | 2004-07-09 | 21134 |
| Lampsilis higginsi (Higgins Eye) #28<br>Location Description: Legal description is too lengthy to fit in allotted space. | LE | END | S1 | G1 | 2004-07-08 | 31904 |
| Lampsilis higginsi (Higgins Eye) #36<br>Location Description: T113N R15W S5, T113N R15W S4, T114N R15W S32, T114N R15W S33 | LE | END | S1 | G1 | 2005-09-29 | 33180 |
| Lampsilis teres (Yellow Sandshell) #19<br>Location Description: T113N R15W S4, T114N R15W S30, T114N R16W S13, T113N R15W S10, T114N R15W S33, T114N R15W S32 | | END | S1 | G5 | 2004-08-02 | 31366 |
| Lesquerella ludoviciana (Bladder Pod) #15<br>Location Description: T113N R15W S21 | | END | S1 | G5 | 1991-10-14 | 32251 |
| Lesquerella ludoviciana (Bladder Pod) #16<br>Location Description: T113N R15W S27 | | END | S1 | G5 | 1993-07-19 | 32252 |
| Ligumia recta (Black Sandshell) #203<br>Location Description: T113N R15W S10, T113N R15W S11, T114N R15W S30 | | SPC | S3 | G5 | 2004-08-02 | 26070 |
| Megalonaias nervosa (Washboard) #13<br>Location Description: T113N R15W S10 | | THR | S2 | G5 | 2004-07-09 | 26030 |
| Megalonaias nervosa (Washboard) #19<br>Location Description: T113N R15W S9, T113N R15W S10, T114N R15W S32, T113N R15W S5, T113N R15W S4, T114N R15W S33 | | THR | S2 | G5 | 2005-09-07 | 31491 |



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|---|---|---|---|---|---|---|
| **Goodhue County, MN** | | | | | | |
| Minuartia dawsonensis (Rock Sandwort) #13<br>Location Description: T113N R16W S9, T113N R16W S4 | | SPC | S3 | G5 | 1990-10-04 | 11742 |
| Native Plant Community, Undetermined Class #400<br>Location Description: T113N R16W S4 | | N/A | SNR | GNR | 1990-10-10 | 11927 |
| Native Plant Community, Undetermined Class #672<br>Location Description: T114N R16W S27 | | N/A | SNR | GNR | 1991-09-26 | 13274 |
| Native Plant Community, Undetermined Class #699<br>Location Description: T113N R15W S21 | | N/A | SNR | GNR | 1991-09-04 | 13337 |
| Native Plant Community, Undetermined Class #856<br>Location Description: T114N R15W S31, T114N R15W S30 | | N/A | SNR | GNR | 1992-09-01 | 14790 |
| Native Plant Community, Undetermined Class #859<br>Location Description: T113N R15W S21, T113N R15W S16 | | N/A | SNR | GNR | 1990-05-22 | 12012 |
| Native Plant Community, Undetermined Class #1051<br>Location Description: T113N R15W S24, T113N R15W S23 | | N/A | SNR | GNR | 1991-09-04 | 14618 |
| Native Plant Community, Undetermined Class #1058<br>Location Description: T113N R15W S6 | | N/A | SNR | GNR | 1992-08-19 | 14959 |
| Native Plant Community, Undetermined Class #1233<br>Location Description: T113N R15W S27 | | N/A | SNR | GNR | 1991-10-14 | 13110 |
| Native Plant Community, Undetermined Class #1324<br>Location Description: T113N R16W S2, T114N R16W S36, T114N R16W S35, T113N R16W S1 | | N/A | SNR | GNR | 1991-08-09 | 13271 |
| Native Plant Community, Undetermined Class #1498<br>Location Description: T113N R16W S12, T113N R16W S11 | | N/A | SNR | GNR | 1991-10-14 | 13270 |
| Native Plant Community, Undetermined Class #1793<br>Location Description: T113N R16W S2, T114N R16W S35 | | N/A | SNR | GNR | 1991-08-09 | 14681 |
| Native Plant Community, Undetermined Class #1860<br>Location Description: T113N R15W S8, T113N R15W S7 | | N/A | SNR | GNR | 1991-09-17 | 13269 |
| Native Plant Community, Undetermined Class #1875<br>Location Description: T114N R16W S34, T114N R16W S26, T114N R16W S35, T114N R16W S27 | | N/A | SNR | GNR | 1990-10-04 | 14963 |
| Native Plant Community, Undetermined Class #1895<br>Location Description: T113N R15W S6 | | N/A | SNR | GNR | 1992-08-19 | 14958 |



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|---|---|---|---|---|---|---|
| **Goodhue County, MN** | | | | | | |
| Native Plant Community, Undetermined Class #2001<br>Location Description: T113N R15W S16, T113N R15W S15 | | N/A | SNR | GNR | 1991-09-04 | 15339 |
| Notropis amnis (Pallid Shiner) #11<br>Location Description: T113N R15W S9, T113N R15W S10 | | SPC | S3 | G4 | 1949 | 16054 |
| Obovaria olivaria (Hickorynut) #78<br>Location Description: T113N R15W S10 | | SPC | S3 | G4 | 2004-07-09 | 26071 |
| Panax quinquefolius (American Ginseng) #76<br>Location Description: T113N R15W S21, T113N R15W S16 | | SPC | S3 | G3G4 | 1990-05-22 | 12108 |
| Panax quinquefolius (American Ginseng) #83<br>Location Description: T113N R16W S1, T113N R15W S6 | | SPC | S3 | G3G4 | 1991-08-09 | 12945 |
| Panax quinquefolius (American Ginseng) #84<br>Location Description: T113N R15W S8, T113N R15W S7 | | SPC | S3 | G3G4 | 1991-09-17 | 12946 |
| Plethobasus cyphyus (Sheepnose) #2<br>Location Description: Legal description is too lengthy to fit in allotted space. | | END | S1 | G3 | 1944-Pre | 21137 |
| Pleurobema coccineum (Round Pigtoe) #77<br>Location Description: T113N R15W S13, T113N R15W S10, T113N R15W S9, T113N R14W S27, T113N R14W S26 | | THR | S2 | G4 | 2004-07-09 | 26072 |
| Pleurobema coccineum (Round Pigtoe) #123<br>Location Description: T114N R16W S13, T114N R15W S30 | | THR | S2 | G4 | 2004-08-02 | 31707 |
| Quadrula metanevra (Monkeyface) #29<br>Location Description: T113N R15W S14, T113N R15W S9, T113N R15W S11, T113N R15W S10, T113N R15W S12, T113N R15W S13 | | THR | S2 | G4 | 2004-07-09 | 21136 |
| Quadrula metanevra (Monkeyface) #37<br>Location Description: T113N R15W S10 | | THR | S2 | G4 | 2000-07-20 | 26060 |
| Quadrula metanevra (Monkeyface) #62<br>Location Description: T114N R15W S30 | | THR | S2 | G4 | 2000-Pre | 31546 |
| Quadrula nodulata (Wartyback) #20<br>Location Description: T113N R15W S10 | | END | S1 | G4 | 1999-07-17 | 26073 |
| Silver Maple - (Virginia Creeper) Floodplain Forest Type #1<br>Location Description: T113N R15W S16, T113N R15W S9 | | N/A | S3 | GNR | 1990-08-08 | 11936 |



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|---|---|---|---|---|---|---|
| **Goodhue County, MN** | | | | | | |
| Silver Maple - (Virginia Creeper) Floodplain Forest Type #10<br>Location Description: T113N R15W S21, T113N R15W S28 | | N/A | S3 | GNR | 1991-09-04 | 13338 |
| Silver Maple - (Virginia Creeper) Floodplain Forest Type #23<br>Location Description: T113N R15W S15 | | N/A | S3 | GNR | 1991-09-04 | 14955 |
| Tritogonia verrucosa (Pistolgrip) #37<br>Location Description: T113N R15W S10 | | THR | S2 | G4G5 | 1999-07- | 26074 |
| **Hennepin County, MN** | | | | | | |
| Native Plant Community, Undetermined Class #1426<br>Location Description: T115N R21W S5, T115N R21W S8 | | N/A | SNR | GNR | 1995-07-06 | 21569 |
| **Hennepin, Scott County, MN** | | | | | | |
| Actinonaias ligamentina (Mucket) #161<br>Location Description: T115N R21W S4, T115N R21W S9, T115N R21W S8, T27N R24W S31 | | THR | S2 | G5 | 1977-03-25 | 28165 |
| Colonial Waterbird Nesting Area (Colonial Waterbird Nesting Site) #249<br>Location Description: T115N R21W S7, T115N R22W S1, T115N R22W S12, T115N R21W S6 | | No Status | SNR | GNR | 1981-06- | 638 |
| Ellipsaria lineolata (Butterfly) #30<br>Location Description: T115N R21W S4, T115N R21W S9, T115N R21W S8, T27N R24W S31 | | THR | S2 | G4 | 1977-03-25 | 28166 |
| Elliptio dilatata (Spike) #133<br>Location Description: T115N R21W S4, T115N R21W S9, T115N R21W S8, T27N R24W S31 | | SPC | S3 | G5 | 1977-03-25 | 28163 |
| Freshwater Mussel Concentration Area (Mussel Sampling Site) #139<br>Location Description: T115N R21W S7, T115N R21W S8 | | No Status | SNR | GNR | 1989-08-25 | 14979 |
| Lasmigona costata (Fluted-shell) #117<br>Location Description: T115N R21W S4, T115N R21W S9, T115N R21W S8, T27N R24W S31 | | SPC | S3 | G5 | 1977-03-25 | 28169 |
| Ligumia recta (Black Sandshell) #224<br>Location Description: T115N R21W S4, T115N R21W S9, T115N R21W S8, T27N R24W S31 | | SPC | S3 | G5 | 1977-03-25 | 28168 |
| Megalonaias nervosa (Washboard) #10<br>Location Description: T115N R21W S4, T115N R21W S9, T115N R21W S8, T27N R24W S31 | | THR | S2 | G5 | 1977-03-25 | 28158 |
| Native Plant Community, Undetermined Class #1391<br>Location Description: T115N R21W S4, T115N R21W S5, T115N R21W S9, T115N R21W S8 | | N/A | SNR | GNR | 1995-06-20 | 21570 |



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|---|---|---|---|---|---|---|
| **Hennepin, Scott County, MN** | | | | | | |
| Obovaria olivaria (Hickorynut) #86<br>Location Description: T115N R21W S4, T115N R21W S9, T115N R21W S8, T27N R24W S31 | | SPC | S3 | G4 | 1977-03-25 | 28167 |
| Pituophis catenifer (Gopher Snake) #10<br>Location Description: T115N R21W S7, T115N R21W S18, T115N R21W S17, T115N R21W S8, T115N R22W S12, T115N R22W S13 | | SPC | S3 | G5 | 1954-05-06 | 8235 |
| Pleurobema coccineum (Round Pigtoe) #88<br>Location Description: T115N R21W S4, T115N R21W S9, T115N R21W S8, T27N R24W S31 | | THR | S2 | G4 | 1977-03-25 | 28162 |
| Spikerush - Bur Reed Marsh (Prairie) Type #1340<br>Location Description: T115N R21W S6 | | N/A | S3 | GNR | 1995-06-30 | 21483 |
| Tritogonia verrucosa (Pistolgrip) #43<br>Location Description: T115N R21W S4, T115N R21W S9, T115N R21W S8, T27N R24W S31 | | THR | S2 | G4G5 | 1977-03-25 | 28159 |
| **Ramsey County, MN** | | | | | | |
| Colonial Waterbird Nesting Area (Colonial Waterbird Nesting Site) #90<br>Location Description: T28N R22W S23, T28N R22W S22 | | No Status | SNR | GNR | 1980 | 532 |
| Haliaeetus leucocephalus (Bald Eagle) #1291<br>Location Description: T28N R22W S23, T28N R22W S22 | LT,PDL | SPC | S3B,S3N | G5 | 1994 | 18700 |
| Scirpus clintonii (Clinton's Bulrush) #6<br>Location Description: T28N R22W S24 | | SPC | S3 | G4 | 1981-05-25 | 11131 |
| **Scott County, MN** | | | | | | |
| Besseya bullii (Kitten-tails) #96<br>Location Description: T115N R21W S21, T115N R21W S16 | | THR | S2 | G3 | 2000-09-19 | 21468 |
| Besseya bullii (Kitten-tails) #121<br>Location Description: T115N R22W S13 | | THR | S2 | G3 | 2002-09-17 | 30167 |
| Calcareous Fen (Southeastern) Type #8<br>Location Description: T115N R21W S17, T115N R21W S16 | | N/A | S1 | GNR | 1980-07- | 241 |
| Calcareous Fen (Southeastern) Type #19<br>Location Description: T115N R21W S17, T115N R21W S16 | | N/A | S1 | GNR | 1992 | 14375 |
| Calcareous Fen (Southeastern) Type #20<br>Location Description: T115N R21W S17 | | N/A | S1 | GNR | 1992 | 14374 |



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**Minnesota Natural Heritage & Nongame Research Program**
**Short Record Report of Element Occurrences within 1 mile radius of:**
Prairie Island Nuclear Generating Plant - Transmission Lines
Multiple TRS
Scott, Dakota, Goodhue, and Washington Counties

| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Scott County, MN** | | | | | | |
| Carex sterilis (Sterile Sedge) #4<br>Location Description: T115N R21W S17, T115N R21W S16 | | THR | S2 | G4 | 1987-08-31 | 4097 |
| Cirsium hillii (Hill's Thistle) #58<br>Location Description: T115N R21W S22, T115N R21W S21, T115N R21W S15, T115N R21W S16 | | SPC | S3 | G3 | 1995-08-21 | 21469 |
| Cirsium hillii (Hill's Thistle) #68<br>Location Description: T115N R21W S22, T115N R21W S21, T115N R21W S15, T115N R21W S16 | | SPC | S3 | G3 | 2000-09-19 | 27330 |
| Cladium mariscoides (Twig-rush) #9<br>Location Description: T115N R21W S17, T115N R21W S16 | | SPC | S3 | G5 | 1980-09-07 | 4202 |
| Cladium mariscoides (Twig-rush) #50<br>Location Description: T115N R21W S17 | | SPC | S3 | G5 | 1987-07-15 | 23012 |
| Colonial Waterbird Nesting Area (Colonial Waterbird Nesting Site) #561<br>Location Description: T115N R22W S1, T115N R22W S12 | | No Status | SNR | GNR | 1982 | 823 |
| Cypripedium candidum (Small White Lady's-slipper) #101<br>Location Description: T115N R21W S17, T115N R21W S9, T115N R21W S8, T115N R21W S16 | | SPC | S3 | G4 | 1981-05-25 | 4383 |
| Cypripedium candidum (Small White Lady's-slipper) #102<br>Location Description: T115N R21W S17, T115N R21W S9, T115N R21W S8, T115N R21W S16 | | SPC | S3 | G4 | 1980-06-08 | 4384 |
| Cypripedium candidum (Small White Lady's-slipper) #133<br>Location Description: T115N R21W S16 | | SPC | S3 | G4 | 1984-05-29 | 4415 |
| Dry Barrens Prairie (Southern) Type #12<br>Location Description: T115N R22W S11 | | N/A | S2 | GNR | 1997-12-01 | 22715 |
| Dry Sand - Gravel Oak Savanna (Southern) Type #4<br>Location Description: T115N R21W S7, T115N R22W S12 | | N/A | S2 | GNR | 1995-06-30 | 1205 |
| Dry Sand - Gravel Prairie (Southern) Type #226<br>Location Description: T115N R21W S16, T115N R21W S22, T115N R21W S21, T115N R21W S15 | | N/A | S2 | GNR | 1995-08-21 | 21467 |
| Eleocharis rostellata (Beaked Spike-rush) #9<br>Location Description: T115N R21W S17 | | THR | S2 | G5 | 1987-07-15 | 10693 |
| Mesic Prairie (Southern) Type #17<br>Location Description: T115N R21W S17, T115N R21W S9, T115N R21W S8, T115N R21W S16 | | N/A | S2 | GNR | 1980-11- | 1270 |
| Native Plant Community, Undetermined Class #1567<br>Location Description: T27N R24W S31, T115N R21W S16, T115N R21W S9, T115N R21W S17 | | N/A | SNR | GNR | 1980-10-25 | 8480 |



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**Minnesota Natural Heritage & Nongame Research Program**
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Prairie Island Nuclear Generating Plant - Transmission Lines
Multiple TRS
Scott, Dakota, Goodhue, and Washington Counties

| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Scott County, MN** | | | | | | |
| Native Plant Community, Undetermined Class #2081<br>Location Description: T115N R21W S18, T115N R21W S17 | | N/A | SNR | GNR | 1995-05- | 17668 |
| Oenothera rhombipetala (Rhombic-petaled Evening Primrose) #19<br>Location Description: T115N R22W S14, T115N R22W S11 | | SPC | S3 | G4G5 | 1995-08-15 | 21479 |
| Perognathus flavescens (Plains Pocket Mouse) #20<br>Location Description: T115N R21W S18, T115N R21W S17 | | SPC | S3 | G5 | 1997-06-25 | 22600 |
| Perognathus flavescens (Plains Pocket Mouse) #21<br>Location Description: T115N R22W S14, T115N R22W S11 | | SPC | S3 | G5 | 1997-07-24 | 22601 |
| Pituophis catenifer (Gopher Snake) #98<br>Location Description: T115N R21W S7 | | SPC | S3 | G5 | 1997-07-28 | 22477 |
| Pituophis catenifer (Gopher Snake) #99<br>Location Description: T115N R22W S11, T115N R22W S10 | | SPC | S3 | G5 | 1997-10-18 | 22479 |
| Pituophis catenifer (Gopher Snake) #105<br>Location Description: T115N R21W S7, T115N R21W S18, T115N R22W S13 | | SPC | S3 | G5 | 1997-07-10 | 27439 |
| Rhynchospora capillacea (Hair-like Beak-rush) #2<br>Location Description: T115N R21W S17, T115N R21W S9, T115N R21W S8, T115N R21W S16 | | THR | S2 | G4 | 1924-09-19 | 5428 |
| Rhynchospora capillacea (Hair-like Beak-rush) #66<br>Location Description: T115N R21W S17 | | THR | S2 | G4 | 1987-08-31 | 23015 |
| Scleria verticillata (Whorled Nut-rush) #6<br>Location Description: T115N R21W S17, T115N R21W S16 | | THR | S2 | G5 | 1981-09-06 | 5567 |
| Scleria verticillata (Whorled Nut-rush) #25<br>Location Description: T115N R21W S17 | | THR | S2 | G5 | 1987-08-31 | 23014 |
| Speyeria idalia (Regal Fritillary) #40<br>Location Description: T115N R22W S1, T115N R22W S13, T115N R22W S12, T115N R22W S11, T115N R22W S14, T115N R22W S2, T115N R21W S7, T115N R21W S18 | | SPC | S3 | G3 | 1965-09-09 | 23534 |
| Sterna forsteri (Forster's Tern) #31<br>Location Description: T115N R21W S7, T115N R21W S6 | | SPC | S3B | G5 | 1981-06-13 | 25159 |
| Valeriana edulis ssp. ciliata (Valerian) #14<br>Location Description: T115N R21W S17, T115N R21W S16 | | THR | S2 | G5T3 | 1987-08-31 | 5839 |



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**Minnesota Natural Heritage & Nongame Research Program**
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Multiple TRS
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| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Scott County, MN** | | | | | | |
| Wilsonia citrina (Hooded Warbler) #10<br>Location Description: T27N R24W S31, T115N R21W S16, T115N R21W S9, T115N R21W S10, T115N R21W S15 | | SPC | S3B | G5 | 1980-05-19 | 25065 |
| **Washington County, MN** | | | | | | |
| Acipenser fulvescens (Lake Sturgeon) #200<br>Location Description: T26N R20W S4 | | SPC | S3 | G3G4 | 1992-08- | 29794 |
| Aflexia rubranura (Red Tailed Prairie Leafhopper) #9<br>Location Description: T27N R20W S29, T27N R20W S28 | No Status | SPC | S3 | G2 | 1993-08-12 | 27585 |
| Besseya bullii (Kitten-tails) #30<br>Location Description: T26N R20W S4 | | THR | S2 | G3 | 1987-05-08 | 7431 |
| Besseya bullii (Kitten-tails) #100<br>Location Description: T27N R20W S28 | | THR | S2 | G3 | 1994-05-25 | 22159 |
| Besseya bullii (Kitten-tails) #110<br>Location Description: T27N R21W S6 | | THR | S2 | G3 | 1998-09-18 | 23836 |
| Botrychium oneidense (Blunt-lobed Grapefern) #22<br>Location Description: T27N R20W S29 | | END | S1 | G4Q | 1997-08-17 | 22521 |
| Botrychium rugulosum (St. Lawrence Grapefern) #30<br>Location Description: T27N R20W S29 | | THR | S2 | G3 | 1995-10-22 | 22913 |
| Buteo lineatus (Red-shouldered Hawk) #28<br>Location Description: T26N R20W S8, T26N R20W S7 | | SPC | S3B,SNRN | G5 | 1988-06-21 | 8758 |
| Buteo lineatus (Red-shouldered Hawk) #29<br>Location Description: T26N R20W S4, T27N R20W S33 | | SPC | S3B,SNRN | G5 | 1981 | 8777 |
| Cirsium hillii (Hill's Thistle) #31<br>Location Description: T27N R20W S29, T27N R20W S28 | | SPC | S3 | G3 | 1990-07-12 | 10564 |
| Coluber constrictor (Eastern Racer) #42<br>Location Description: T28N R21W S31 | | SPC | S3 | G5 | 1994-05-30 | 18910 |
| Cycleptus elongatus (Blue Sucker) #73<br>Location Description: T26N R20W S4 | | SPC | S3 | G3G4 | 1997-08-19 | 23197 |
| Cycleptus elongatus (Blue Sucker) #99<br>Location Description: T26N R20W S4 | | SPC | S3 | G3G4 | 1997-08-19 | 29809 |



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**Minnesota Natural Heritage & Nongame Research Program**
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| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Washington County, MN** | | | | | | |
| Dry Bedrock Bluff Prairie (Southern) Type #110<br>Location Description: T27N R20W S28, T27N R20W S20, T27N R20W S21, T27N R20W S29 | | N/A | S3 | GNR | 1987-05-08 | 7470 |
| Dry Bedrock Bluff Prairie (Southern) Type #112<br>Location Description: T27N R20W S28 | | N/A | S3 | GNR | 1987-08-24 | 7469 |
| Dry Bedrock Bluff Prairie (Southern) Type #113<br>Location Description: T27N R20W S21 | | N/A | S3 | GNR | 1987-08-24 | 7472 |
| Dry Bedrock Bluff Prairie (Southern) Type #114<br>Location Description: T27N R20W S17, T27N R20W S16 | | N/A | S3 | GNR | 1987-08-27 | 7464 |
| Dry Bedrock Bluff Prairie (Southern) Type #118<br>Location Description: T27N R21W S8, T27N R21W S7 | | N/A | S3 | GNR | 1987-08-19 | 7476 |
| Dry Sand - Gravel Prairie (Southern) Type #15<br>Location Description: T27N R21W S16, T27N R21W S15 | | N/A | S2 | GNR | 1987-09-22 | 7488 |
| Dry Sand - Gravel Prairie (Southern) Type #16<br>Location Description: T27N R21W S23, T27N R21W S22 | | N/A | S2 | GNR | 1987-09-22 | 7461 |
| Dry Sand - Gravel Prairie (Southern) Type #17<br>Location Description: T27N R21W S27, T27N R21W S23, T27N R21W S22, T27N R21W S26 | | N/A | S2 | GNR | 1987-09-22 | 7485 |
| Dry Sand - Gravel Prairie (Southern) Type #22<br>Location Description: T26N R20W S5 | | N/A | S2 | GNR | 1987-05-16 | 7468 |
| Dry Sand - Gravel Prairie (Southern) Type #187<br>Location Description: T28N R22W S36 | | N/A | S2 | GNR | 1987-08-19 | 7489 |
| Emydoidea blandingii (Blanding's Turtle) #664<br>Location Description: T28N R22W S26, T28N R22W S25 | | THR | S2 | G4 | 1991-05-16 | 18822 |
| Emydoidea blandingii (Blanding's Turtle) #1012<br>Location Description: T27N R21W S27, T27N R21W S23, T27N R21W S22, T27N R21W S26 | | THR | S2 | G4 | 2002-05-17 | 30032 |
| Haliaeetus leucocephalus (Bald Eagle) #942<br>Location Description: T26N R20W S8 | LT,PDL | SPC | S3B,S3N | G5 | 1991-Pre | 12122 |
| Juniperus horizontalis (Creeping Juniper) #35<br>Location Description: T26N R20W S4 | | SPC | S3 | 5 | 1976-11-13 | 6166 |
| Minuartia dawsonensis (Rock Sandwort) #10<br>Location Description: T27N R20W S29, T27N R20W S28 | | SPC | [illegible] | 5 | 1987-05-08 | 7410 |



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**Minnesota Natural Heritage & Nongame Research Program**
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Prairie Island Nuclear Generating Plant - Transmission Lines
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| Element Name and Occurrence Number | Federal Status | MN Status | State Rank | Global Rank | Last Observed Date | EO ID # |
|---|---|---|---|---|---|---|
| **Washington County, MN** | | | | | | |
| Minuartia dawsonensis (Rock Sandwort) #11<br>Location Description: T27N R20W S21 | | SPC | S3 | G5 | 1987-08-24 | 7449 |
| Minuartia dawsonensis (Rock Sandwort) #12<br>Location Description: T27N R20W S17, T27N R20W S16 | | SPC | S3 | G5 | 1987-08-27 | 7448 |
| Native Plant Community, Undetermined Class #475<br>Location Description: T27N R21W S27, T27N R21W S23, T27N R21W S22, T27N R21W S26 | | N/A | SNR | GNR | 1988-07-20 | 8665 |
| Oak - (Red Maple) Woodland Type #1174<br>Location Description: T28N R22W S25, T28N R22W S36, T28N R21W S30, T28N R21W S31 | | N/A | S4 | GNR | 1971-05-21 | 9375 |
| Opuntia macrorhiza (Plains Prickly Pear) #19<br>Location Description: T27N R20W S29, T27N R20W S28 | | SPC | S3 | G5 | 1991-03-20 | 11900 |
| Panax quinquefolius (American Ginseng) #41<br>Location Description: T26N R20W S4 | | SPC | S3 | G3G4 | 1988-06-08 | 8522 |
| **Non-MN County - Located just outside Minnesota in adjacent jurisdiction(s).** | | | | | | |
| Haliaeetus leucocephalus (Bald Eagle) #575<br>Location Description: Just outside Minnesota in adjacent jurisdiction(s). | LT,PDL | SPC | S3B,S3N | G5 | 1990 | 8201 |
| Haliaeetus leucocephalus (Bald Eagle) #984<br>Location Description: Just outside Minnesota in adjacent jurisdiction(s). | LT,PDL | SPC | S3B,S3N | G5 | 1991 | 13047 |
| Haliaeetus leucocephalus (Bald Eagle) #1125<br>Location Description: Just outside Minnesota in adjacent jurisdiction(s). | LT,PDL | SPC | S3B,S3N | G5 | 1994 | 15405 |
| Haliaeetus leucocephalus (Bald Eagle) #1264<br>Location Description: Just outside Minnesota in adjacent jurisdiction(s). | LT,PDL | SPC | S3B,S3N | G5 | 1994 | 17000 |
| Haliaeetus leucocephalus (Bald Eagle) #1524<br>Location Description: Just outside Minnesota in adjacent jurisdiction(s). | LT,PDL | SPC | S3B,S3N | G5 | 1998 | 21803 |
| Tritogonia verrucosa (Pistolgrip) #63<br>Location Description: Just outside Minnesota in adjacent jurisdiction(s). | | THR | S2 | G4G5 | 2000-Pre | 31493 |

**Records Printed** = 367



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NMC
Committed to Nuclear Excellence

Xcel Energy

January 25, 2008

Ms. Lisa Joyal
Endangered Species Environmental Review Coordinator
Natural Heritage and Nongame Research Program
Division of Ecological Resources
Minnesota Department of Natural Resources
500 Lafayette Road, Box 25
St. Paul, Minnesota 55155

SUBJECT: Prairie Island Nuclear Generating Plant License Renewal
Request for Information on Threatened and Endangered Species

Dear Ms. Joyal:

Nuclear Management Company (NMC), acting on behalf of Northern States Power Company, a wholly-owned subsidiary of Xcel Energy, would like to thank the Minnesota Department of Natural Resources (MNDNR) Natural Heritage and Nongame Research Program for providing information regarding rare plant or animal species, and other significant natural features present on or within the vicinity of the Prairie Island Nuclear Generating Plant (PINGP) site and associated transmission lines on June 15 and August 9, 2007, respectively. This information provided by MNDNR concerning occurrences of rare species and natural communities on the PINGP site and associated transmission corridors has been utilized in order to assess potential impacts on threatened and endangered species, should PINGP continue to operate for an additional twenty years.

PINGP is finalizing its application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for PINGP, which expire in 2013 (Unit 1) and 2014 (Unit 2). As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened and endangered species in accordance with the Endangered Species Act" and will almost certainly seek your agency's assistance in the identification of important species and habitats in the project area. By contacting you in advance, we hope to identify any issues that need to be addressed or any information your office may need to expedite the NRC consultation.

Renewal of the PINGP operating licenses would not involve any land disturbance, any changes to plant operations, or any modifications of the transmission system that connects the plant to the regional electric grid. There are plans, however, to replace the Unit 2 steam generators in the fall of 2013, one year before the Unit 2 operating license expires. The steam generators would arrive by barge, and would be installed within the Unit 2 containment structure. Temporary buildings and parking areas would be necessary, but these facilities would be constructed in previously-disturbed areas. Because, in all likelihood, Northern States Power would not replace the steam generators were it not seeking approval for an additional 20 years of operation, we have considered environmental impacts of steam generator replacement in the Environmental Report we are submitting to the NRC. In NEPA parlance, it is a "connected action" (40 CFR 1508.25). We would therefore appreciate your taking steam generator replacement into consideration when you conduct your review of the project's potential effect on threatened or endangered species.

NMC would appreciate your review of the following assessment summary, and transmittal of written concurrence, or concerns, relative to the following conclusions that continued operation of

PINGP would have little or no adverse effect on threatened and endangered species in the vicinity of the site. NMC does not expect renewal of the PINGP operating license to negatively impact state or federally listed threatened and endangered species, jeopardize the continued existence of such species, or result in destruction or adverse alteration of any critical natural habitats.

Area of Concern

The PINGP site, located in Goodhue County, Minnesota, consists of 578 acres on the west bank of the Mississippi River, within the city limits of Red Wing, Minnesota (Figure 1). The City of Hastings is located approximately 13 miles northwest (upstream) of the plant. Minneapolis is located approximately 39 miles northwest and St. Paul is located approximately 32 miles northwest of the plant. At the plant location, the Mississippi River serves as the state boundary between Minnesota and Wisconsin. PINGP is located on the western shore of Sturgeon Lake, a backwater area located one mile upstream from the U.S. Army Corps of Engineers (USACE) Lock and Dam No. 3. The Vermillion River lies just west of PINGP and flows into the Mississippi River approximately two miles downstream of Lock and Dam No. 3.

Figure 2 shows the property boundary and exclusion zone, which is restricted by a perimeter fence with "No Trespassing" signs. Access to the exclusion zone by water is not restricted by a fence; however, "No Trespassing" signs are placed at intervals along the shoreline of the river. East of the plant the exclusion zone boundary extends to the main channel of the Mississippi River. Islands within this boundary as well as a small strip of land northeast of the plant are owned by the Corps of Engineers.

Directly north of Xcel property lies the Prairie Island Indian Community and Reservation, a federally recognized Indian Tribe organized under the Indian Reorganization Act. The Prairie Island Indian Community owns and operates the Treasure Island Resort and Casino, a 250-room hotel and convention center that is currently being expanded. It offers gaming, dining, live entertainment, an RV park, a 137-slip marina to accommodate visitors arriving by the Mississippi River, and sightseeing and dinner cruises on their river boat.

Five transmission lines connect PINGP to the regional electric system. The transmission system is depicted in Figures 3 and 4. The output of PINGP is delivered to the substation just north of the generating facilities with 345-kV and 161-kV switchyards, where five transmission lines leave via three transmission corridors. The transmission lines include two 2.5 mile (Red Rock 1 and Adams) transmission connections, the Red Rock 2 connection to the Red Rock Substation in St. Paul, the Blue Lake Substation connection, and the Spring Creek Substation connection.

Transmission corridors are maintained by Xcel Energy and Great River Energy using an Integrated Vegetation Management (IVM) approach that includes both mechanical and chemical control methods. In particular, both wetland and upland habitats are maintained in low-growing vegetation through the use of manual cutting and the selective application of EPA-approved herbicides resulting in the open habitats preferred by threatened or endangered species.

NMC does not expect PINGP operations through the period of extended operation (an additional 20 years) to significantly affect any threatened or endangered species in the area. Nor does NMC expect steam generator replacement to adversely impact ecological resources on site because the project will not involve ground disturbing activities in any previously undisturbed areas.

We would appreciate your sending a letter detailing any concerns you may have about potential impacts to threatened or endangered species (or their habitats) in the area of PINGP or confirming NMC's conclusion that operation of PINGP over the license renewal term would have no effect on these species. NMC will include a copy of this letter and your response in the license renewal application that we submit to the NRC.

Again, thank you for your previous assistance providing PINGP with rare and threatened species and habitat information. We look forward to continuing to work with the MNDNR through the license renewal process. Please direct any requests for additional information, questions and your response to:

James J. Holthaus, PMP
Environmental Project Manager
Prairie Island Nuclear Generating Plant
1717 Wakonade Drive East
13 – Plex (License Renewal)
Welch, MN 55089
651-388-1121 ext 7268

Sincerely,

Mike Wadley

Mike Wadley
Prairie Island Site Vice President
Nuclear Management Company

Enclosures: Figure 1
Figure 2
Figure 3
Figure 4

Figure 1
PINGP 50-Mile Radius

Figure 2
PINGP Site Boundary

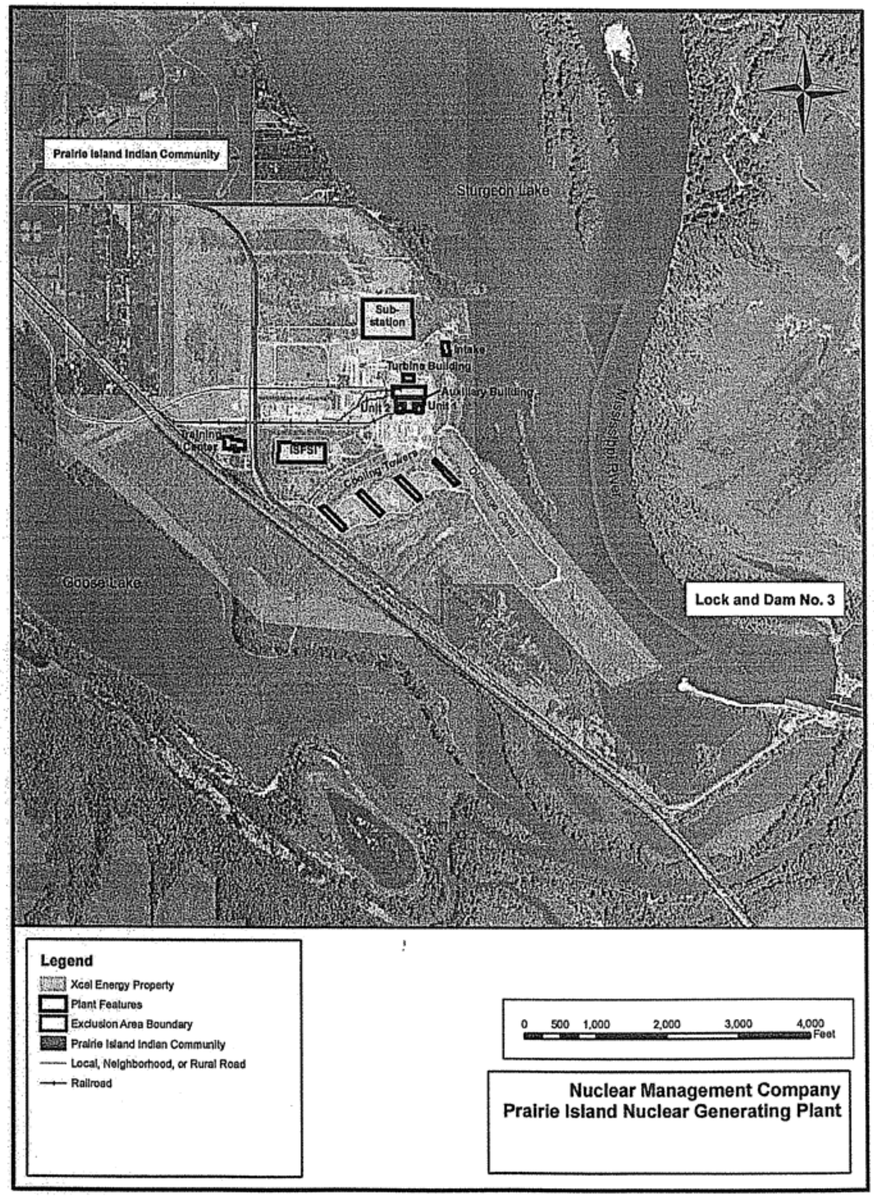


Figure 3
PINGP Site Transmission Line Layout

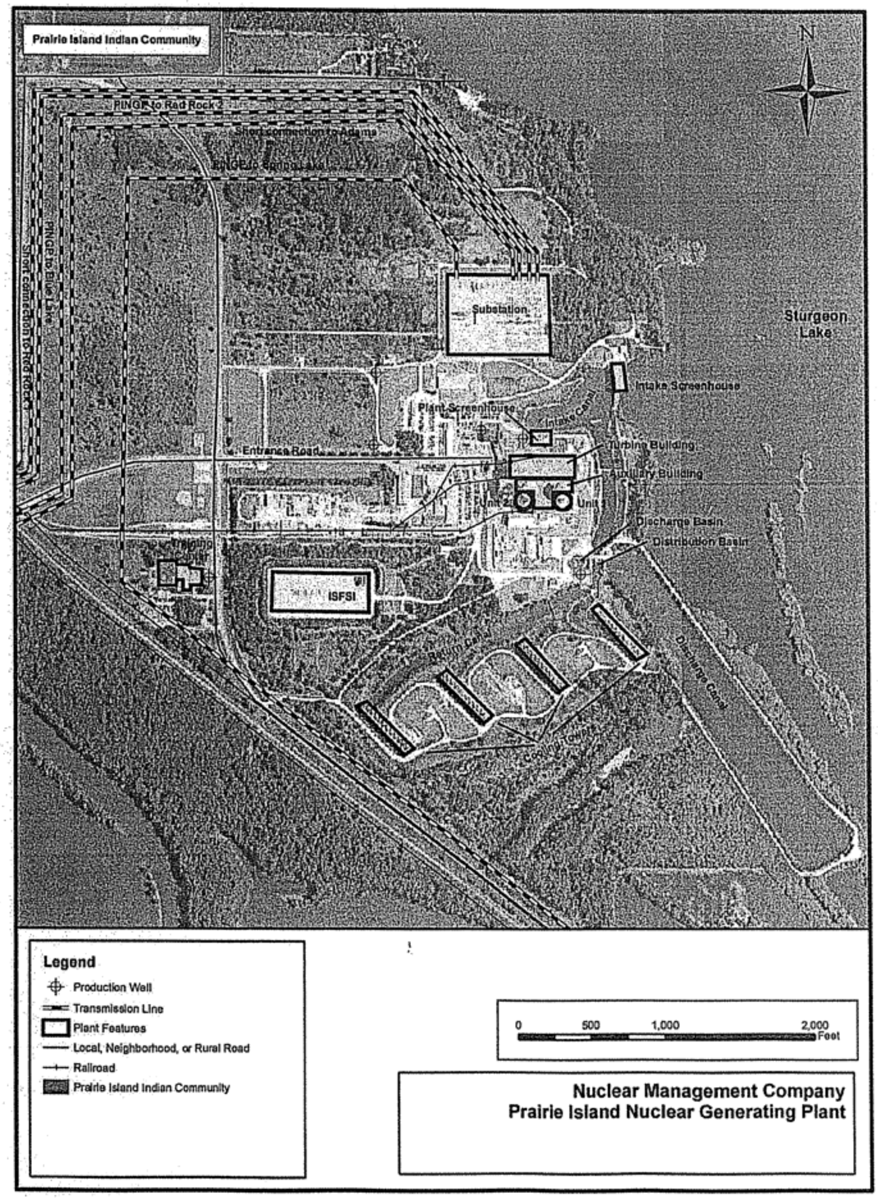
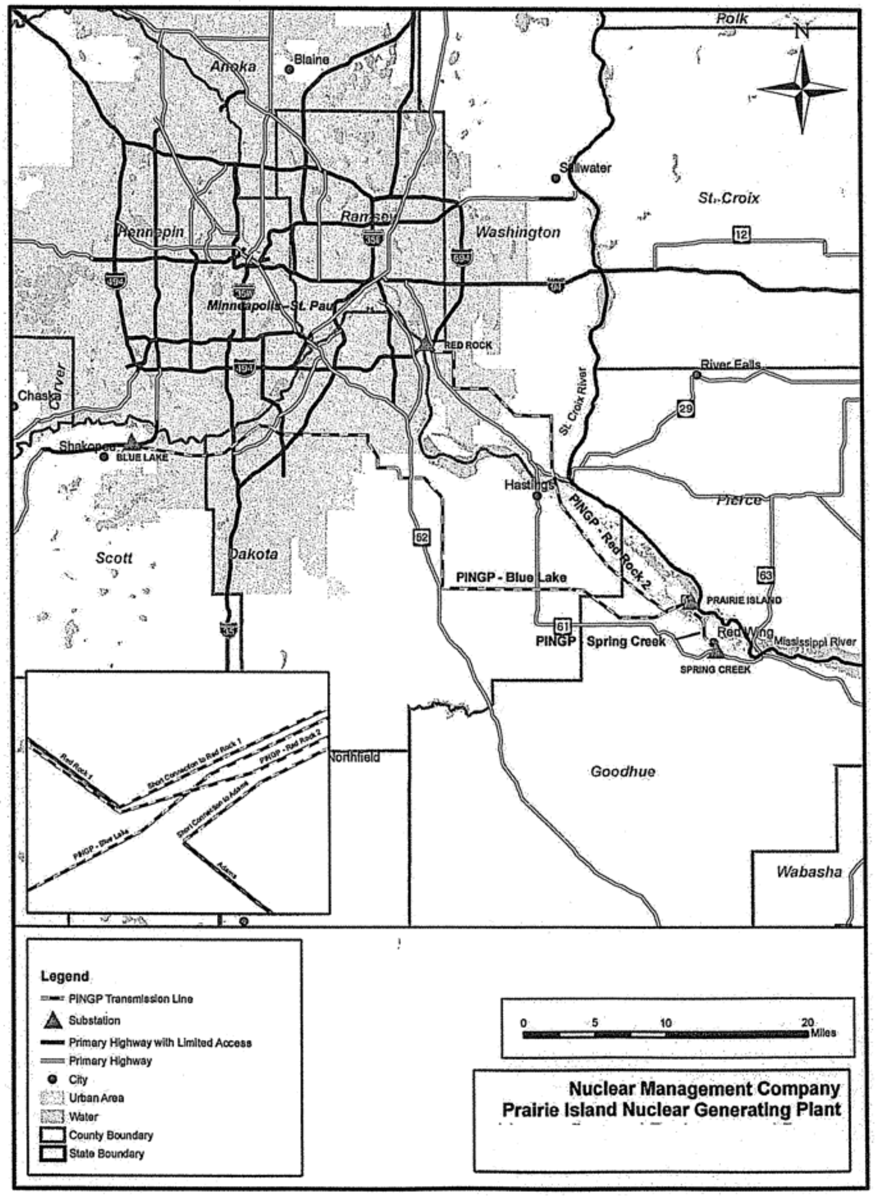


Figure 4
PINGP Transmission Outlets



# ATTACHMENT D

# STATE HISTORIC PRESERVATION OFFICER CORRESPONDENCE

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Mike Wadley (Nuclear Management Company) to Dennis Gimmestad (State Historic Preservation Office, Minnesota Historical Society) — D-3

NMC
Committed to Nuclear Excellence

Xcel Energy

March 24, 2008

Mr. Dennis A. Gimmestad
Government Programs and Compliance Officer
State Historic Preservation Office
Minnesota Historical Society
345 Kellogg Boulevard West
Saint Paul, Minnesota 55102-1903

SUBJECT: Prairie Island Nuclear Generating Plant License Renewal Project
Goodhue County
SHPO Number: 2007-1880

Dear Mr. Gimmestad:

Nuclear Management Company ("NMC"), acting on behalf of Northern States Power Company, a Minnesota corporation ("Xcel Energy" or "the Company") would like to thank the Minnesota State Historic Preservation Office (SHPO) for providing comments on the April 30, 2007 letter regarding renewal of the Prairie Island Nuclear Generating Plant ("PINGP") operating license. We appreciate the time your agency has taken to review the letter as well as identify concerns pertaining to Section 106 requirements and asking about how cultural resource issues will be addressed in the environmental review. Below we are providing additional information on the issues raised in your June 7, 2007 letter.

The Nuclear Regulatory Commission ("NRC") will formally consult with your office at a later date under Section 106 of the *National Historic Preservation Act* of 1966, as amended (16 USC 470), and Federal Advisory Council on Historic Preservation regulations (36 CFR 800). In order to expedite the formal process and to foster an integrated approach, we would like to work with you now to identify any issues that should be addressed or any information your office may need to expedite the NRC consultation.

The cultural resource issues addressed in the Environmental Report (Chapter 2 and Chapter 4) were researched in the environmental review process, and will continue to be reviewed as the License Renewal process moves forward. NMC contracted with a company named The 106 Group Ltd. to perform a cultural resources assessment of the PINGP site to document past studies and to provide information that would assist NMC with planning and avoidance of known resources. Their records search revealed that four professional archeological surveys and one testing project have been conducted within plant boundaries (Figure 1). Within the plant boundaries, seven archeological sites have been recorded. One site, the Bartron Site, is listed on the National Register of Historic Places. Within one mile of the plant boundary, 16 archeological sites have been recorded (15 are on the Minnesota side of the Mississippi River). The assessment also identified areas that are thought to be previously disturbed from original construction of the PINGP. The cultural resources assessment prepared by The 106 Group is included as Attachment 1 to this letter.

The Prairie Island Indian Community (PIIC) Reservation is located directly north of the PINGP. The PIIC is a sovereign nation federally recognized under the Indian Reorganization Act. NMC and the PINGP staff have a long-standing relationship with and history of consulting with PIIC's tribal council and technical staff regarding community concerns, business proposals, emergency planning, plant operations, and other items of mutual interest. NMC is consulting with the PIIC regarding the proposed license renewal and refurbishment activities (addressed later in this letter) at PINGP.

Consultation was initiated by Xcel Energy and NMC via a letter sent July 25, 2007 requesting PIIC's participation in the license renewal application process and seeking input regarding any concern PIIC has for historical, archaeological, cultural or other environmental resources. Xcel Energy and NMC management met with the PIIC tribal council on September 24, 2007 to discuss the license renewal application process, and license renewal and PINGP site staff met with PIIC technical staff on November 8, 2007.

On February 7, 2008, PIIC submitted a letter to PINGP detailing their comments and concerns with regard to environmental issues. PIIC has requested a copy of the cultural resource assessment, which will be provided to them along with your response to this consultation request. They have requested that a buffer be instituted around all known archeological resources to prevent future disturbance. The PIIC is concerned about two sites that may have been impacted previously during original construction of the plant. They have requested implementation of a collaborative program of surveying on the plant site to record all cultural resources and their condition; identification of restoration activities for cultural resources previously impacted; and access to a burial site by tribal members for ceremonial purposes. The PINGP will continue consultation with the PIIC to address their requests.

In addition to the aforementioned efforts, NMC and Xcel Energy are working with Minnesota State University - Mankato ("Mankato State") to perform further studies on the Bartron Site during Summer 2008. Mankato State plans to hold a field school to do the initial digs and documentation, with a formal write-up and necessary follow-up work performed through a Master's thesis by a graduate student(s). The PIIC is aware of these efforts and has supported Mankato State's efforts financially.

At this time there are no plans for PINGP site alteration due to the license renewal project. Any future site alterations will comply with permitting requirements administered by the City of Red Wing, Goodhue County and the State of Minnesota. However, there are plans to replace the Unit 2 steam generators in the fall of 2013, one year before Unit 2's current operating license expires. Because, in all likelihood, the Company would not replace the steam generators were it not seeking approval for an additional 20 years of operation, we have considered environmental impacts of steam generator replacement in the Environmental Report we are submitting to the NRC. We believe that in NEPA parlance, this is a "connected action" (40 CFR 1508.25). Therefore, we believe it is reasonable for your agency to consider the steam generator replacement at Unit 2 when you conduct your review of the project's potential effect on historic and cultural resources.

The steam generators are planned to arrive at the PINGP loading dock by barge and transported to the Unit 2 containment building by truck on an existing paved road (Figure 2). The old generators will be removed from the Unit 2 containment building and the new ones installed in the same location inside the Unit 2 containment building. The new generators are similar in size and mass as the originals and have the same function. Temporary construction facilities, such as mobile trailers, a staging area, and parking area, would be necessary, but these temporary facilities would be located nearby in previously disturbed areas and away from known cultural resources. These areas have been identified in the attached cultural resource assessment (see specifically Figure 2 of the attached cultural resources assessment) as previously disturbed, with little to no potential for intact archaeological deposits.

The Company has concluded that renewal of the PINGP operating licenses and activities planned during the 20-year term of the new licenses, including replacement of the Unit 2 steam generators, will result in no adverse effects on historic and archaeological resources. PINGP will continue to follow established procedures for avoidance and protection of archaeological, historic, and cultural resources (see Appendix A of the attached cultural resources assessment). As stated previously, refurbishment activities will be conducted within previously disturbed areas of the site. However, during ground-disturbing activities, if archaeological materials are discovered in the work area, activities in the vicinity of the discovery would stop and the Company will have the discovery assessed by a professional archaeologist and will consult with your office.

Since we will included a copy of this letter in the license renewal application that we submit to the NRC, it would greatly assist our application to the NRC if we could receive a a written response from your office detailing any concerns you may have about potential adverse effects to historic and archaeological resources, or confirming the Company's conclusion that operation of PINGP over the license renewal term would have no adverse effects to historic and archaeological resources.

If you have any questions or require any additional information to review the proposed action, please feel free to contact Mr. James Holthaus, Environmental Project Manager, at 651-388-1121, ext. 7268, or via email at james.holthaus@nmcco.com.

Sincerely,

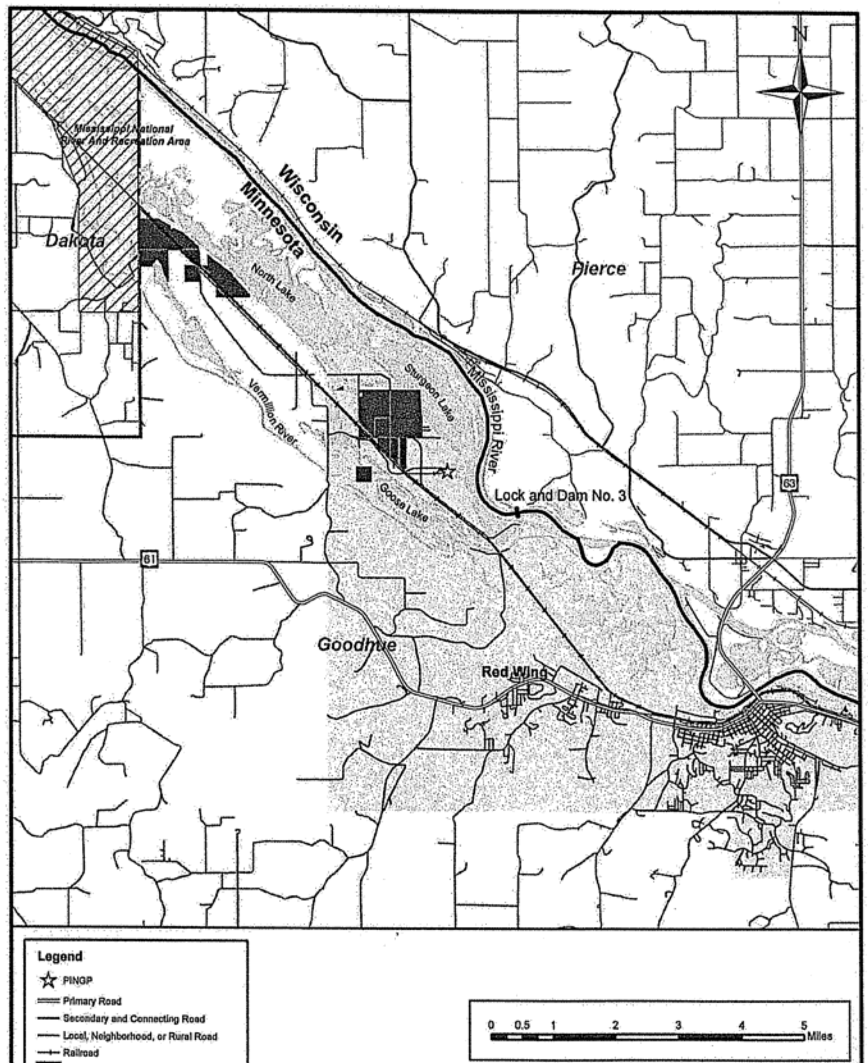
Mike Wadley

Mike Wadley
Site Vice President
Prairie Island Nuclear Generating Plant

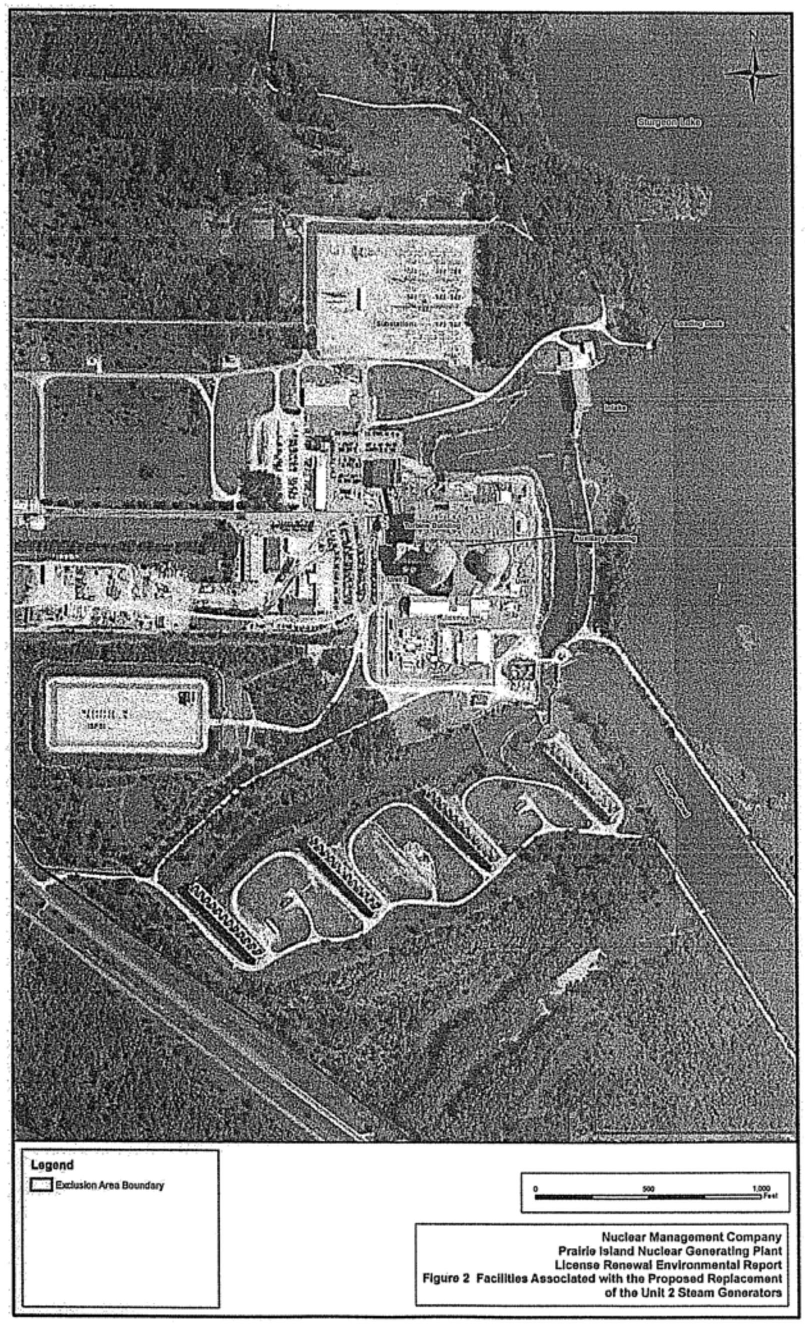
Enclosures:
Figure 1 – Location of Prairie Island Nuclear Generating Plant
Figure 2 – Facilities Associated with the Proposed Replacement of the Unit 2 Steam Generators
Attachment 1 – *Cultural Resources Assessment for the Prairie Island Nuclear Generating Plant, Goodhue County, Minnesota*, January 2008, The 106 Group Ltd.

cc w/encl.: President, Prairie Island Indian Community

3




Nuclear Management Company
Prairie Island Nuclear Generating Plant
License Renewal Environmental Report
Figure 1 Location of Prairie Island Nuclear Generating Plant




Nuclear Management Company
Prairie Island Nuclear Generating Plant
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Figure 2 Facilities Associated with the Proposed Replacement of the Unit 2 Steam Generators

# ATTACHMENT E

# PUBLIC HEALTH AGENCY CORRESPONDENCE

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NMC Committed to Nuclear Excellence

Xcel Energy

January 25, 2008

Mr. John Linc Stine, Director
Environmental Health Division
Minnesota Department of Health
625 Robert Street
St. Paul, Minnesota 55164-0975

SUBJECT: Prairie Island Nuclear Generating Plant License Renewal
Request for Information on Thermophilic Microorganisms

Dear Mr. Stine:

Nuclear Management Company (NMC), acting on behalf of Northern States Power Company, a wholly-owned subsidiary of Xcel Energy, is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for Prairie Island Nuclear Generating Plant (PINGP), which expire in 2013 (Unit 1) and 2014 (Unit 2). As part of the license renewal process, NRC requires license applicants to provide "...an assessment of the impact of the proposed action {license renewal} on public health from thermophilic organisms in the affected water." Organisms of concern include the enteric pathogens *Salmonella* and *Shigella*, the *Pseudomonas aeruginosa* bacterium, thermophilic Actinomycetes ("fungi"), the many species of *Legionella* bacteria, and pathogenic strains of the free-living *Naegleria* amoeba.

As part of the license renewal process, NMC is consulting with your office to determine whether there is any concern about the potential occurrence of these organisms in the Mississippi River at the location of PINGP. On June 14, 2007 your office indicated there were no concerns at that time. As stated in the September 7, 2007 letter from James Holthaus, we are currently seeking your input on any specific concerns the Department may have regarding thermophilic microorganisms. By contacting you, we hope to identify any issues that need to be addressed or any information your office may need to expedite the NRC consultation.

The PINGP site, located in Goodhue County, Minnesota, consists of 578 acres on the west bank of the Mississippi River (Figure 1), within the city limits of Red Wing, Minnesota. The Vermillion River lies just west of PINGP and flows into the Mississippi River approximately two miles downstream of Lock and Dam No. 3 (Figure 2). NRC regulations specify that if discharges are made to a small river with an average annual flow rate of less than $3.15 \times 10^{12}$ cubic feet per year, the applicant must assess the public health impacts of the proposed action regarding potential proliferation of thermophilic microbiological organisms in the affected waters. As a component of its operation, PINGP discharges cooling water into the Mississippi River. The Mississippi River has an average flow of $5.8 \times 10^{11}$ cubic feet per year in the vicinity of PINGP, conforming to the NRC definition for consideration as a small river. This issue is therefore applicable to PINGP license renewal and will be addressed in the Environmental Report.

To determine the ambient river water temperature, assess the plant's thermal output, and assure compliance with NPDES thermal discharge requirements, river water is monitored by PINGP at multiple locations. Temperatures are monitored in the main river channel (upstream), Sturgeon Lake (upstream), the plant intake structure, the discharge canal, and immediately downstream of Lock and Dam Number 3. The highest temperature at the station upstream of the plant intake structure during the period of 2000-2005 was 86.0°F in 2001 (August 8). The highest temperature measured over the same period downstream of the plant at the Lock and Dam Number 3 monitoring station was 86.4°F in 2001 (August 9). The highest daily maximum temperature measured at the plant's discharge canal from January 2003 through December 2004 was 99.0°F, recorded on July 28, 2003. The entire length of the discharge canal and adjoining portions of the Mississippi River are within the plant's exclusion zone, however, and there is no public access to these areas. Water at these temperatures could, in theory, allow limited survival of thermophilic microorganisms, but are well below the optimal temperature range for growth and reproduction of thermophilic microorganisms. Thermophilic bacteria generally occur at temperatures from 77°F to 176°F, with maximum growth at 122°F to 140°F. The probability of the presence of thermophilic microorganisms due to plant operations is low.

During the early 1980s, PINGP identified the presence of the parasitic amoeba *Naegleria* at high population densities within the plant's circulating water system. In cooperation with the Minnesota Pollution Control Agency and Minnesota Department of Natural Resources, PINGP conducted chlorination and subsequent dechlorination of the circulating water system in August 1980, September 1981, and August 1983. The chlorination processes were successful in controlling and reducing the populations of the organisms; however, the dechlorination process does impact the fish populations in the Mississippi River. Although the Minnesota Department of Health did not consider the presence of the organism to be a public health threat, it was recognized as an occupational health hazard and plant personnel were instructed to wear protective equipment when in contact with the circulating water system components. PINGP continues to periodically chlorinate the circulating water system to control microbiological organisms and zebra mussels in accordance with the NPDES permit requirements.

Given the thermal characteristics at the PINGP discharge and the fact that NMC periodically chlorinates the circulating water system, NMC does not expect PINGP operations to stimulate growth or reproduction of thermophilic microorganisms. Under certain circumstances, these organisms might be present in limited numbers in the station's discharge, but would not be expected in concentrations high enough to pose a threat to recreational users of the Mississippi River.

We appreciate your earlier response to general License Renewal issues. We would appreciate a letter detailing any concerns you may have about thermophilic microorganisms in the area of PINGP or confirming NMC's conclusion that operation of PINGP over the license renewal term would not stimulate growth of thermophilic pathogens. NMC will include a copy of this letter and your response in the license renewal application that we submit to the NRC.

Please direct any requests for additional information, questions and your response to:

James J. Holthaus, PMP
Environmental Project Manager
Prairie Island Nuclear Generating Plant
1717 Wakonade Drive East
13 – Plex (License Renewal)
Welch, MN 55089
651-388-1121 ext 7268
James.holthaus@nmcco.com

Sincerely,

Mike Wadley

Mike Wadley
Prairie Island Site Vice President
Nuclear Management Company

Enclosures: Figure 1
Figure 2

Figure 1
PINGP Site Boundary

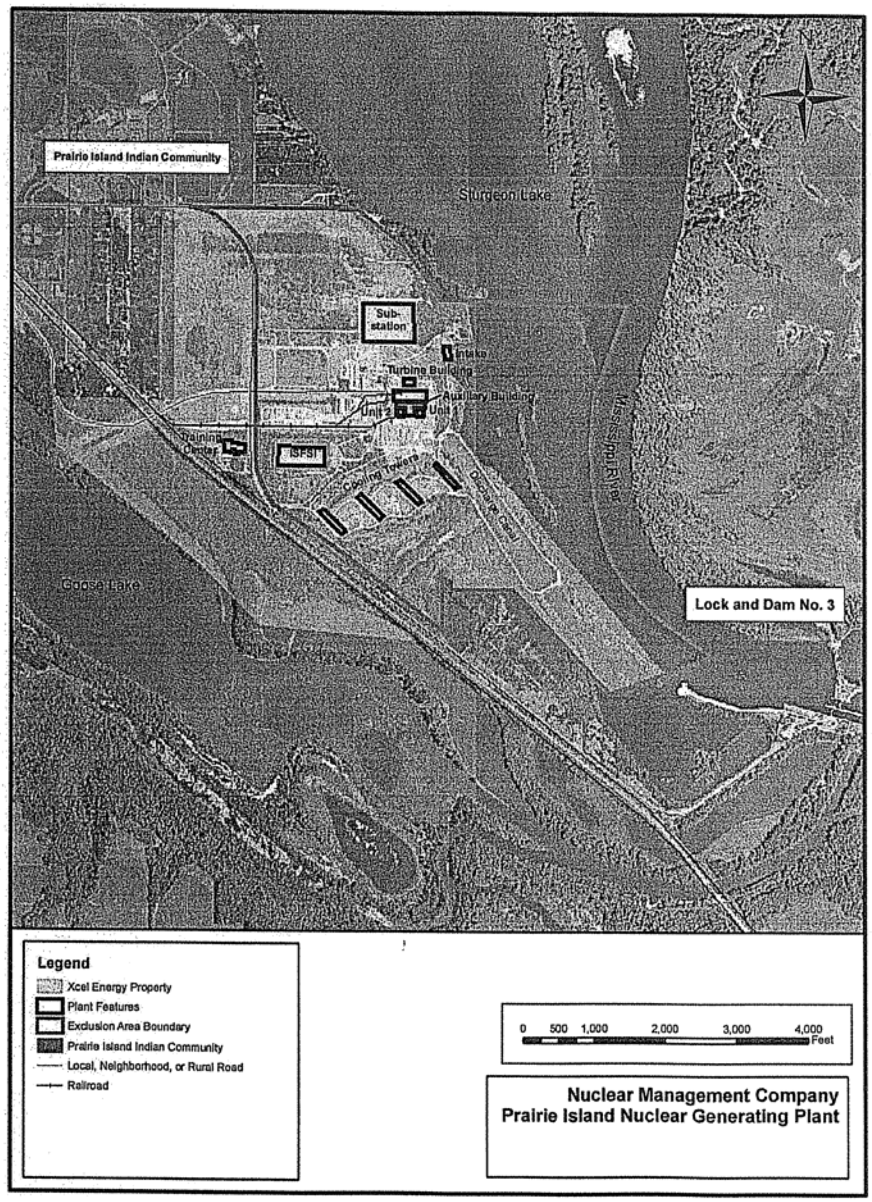
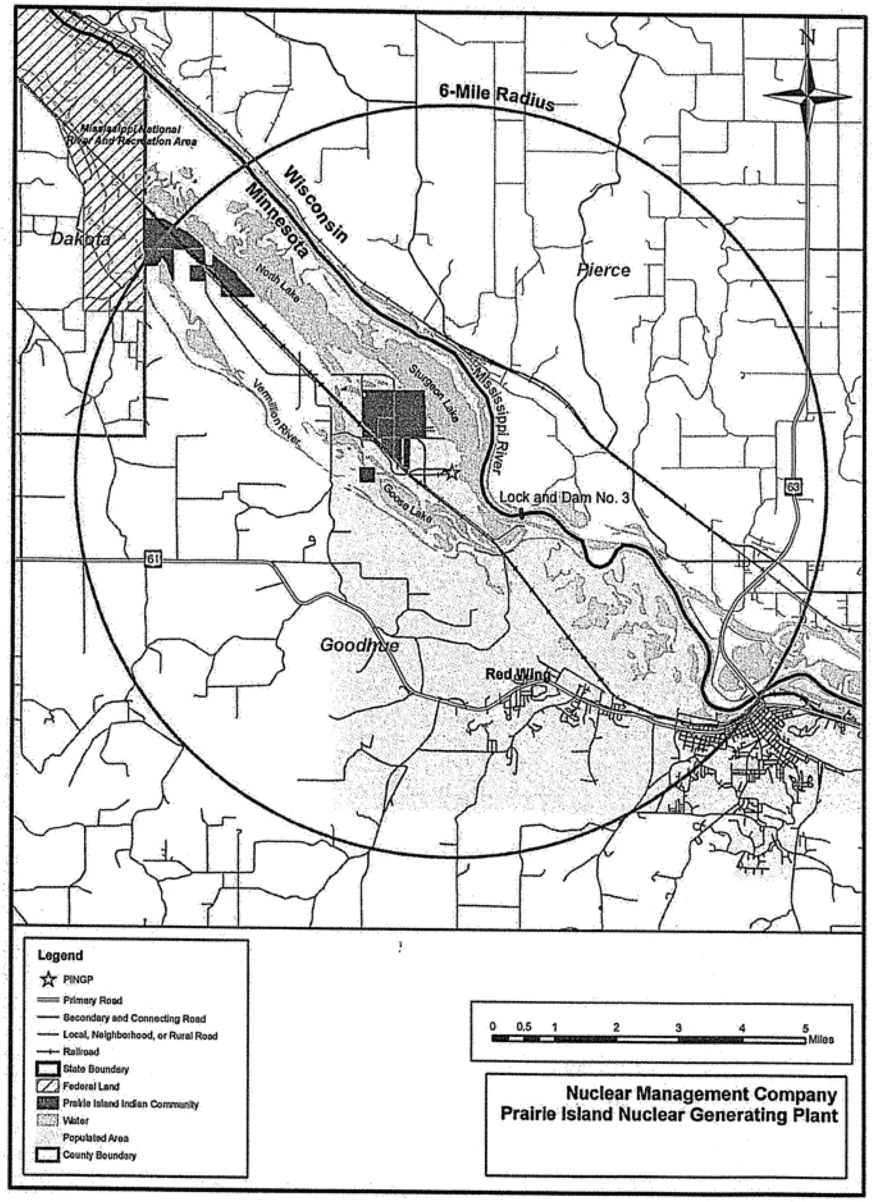


Figure 2
6-Mile Radius of PINGP



# ATTACHMENT F

# SEVERE ACCIDENT MITIGATION ALTERNATIVES

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## Acronyms Used in Attachment F

| | |
|---|---|
| AFW | auxiliary feedwater |
| AOP | abnormal operating procedure |
| AOV | air operated valve |
| ASME | American Society of Mechanical Engineers |
| ATWS | anticipated transient without scram |
| BAST | boric acid storage tank |
| BE | basic event |
| BWR | boiling water reactor |
| CAP | corrective action program |
| CC | component cooling |
| CCF | common cause failure |
| CCFP | conditional containment failure probability |
| CD | core damage |
| CDB | core damage bin |
| CDF | core damage frequency |
| CET | containment event tree |
| CL | cooling water system |
| CRD | control rod drive |
| CS | containment spray |
| CST | condensate storage tank |
| CVCS | chemical and volume control system |
| DDCLP | diesel-driven cooling water pump |
| DDFP | Diesel-driven fire pump |
| ECCS | emergency core cooling system |
| EDG | emergency diesel generator |
| EOF | emergency operations facility |
| EOP | emergency operating procedure |
| EPRI | electric power research institute |
| EPZ | emergency planning zone |
| F&O | fact and observation |
| FA | fire area |
| FC | fail closed |
| FHA | fuel handling accident |
| FIVE | Fire Induced Vulnerability Evaluation |
| FP | fire protection |
| FPS | fire protection system |
| FT | fault tree |
| FTC | fails to close |
| FTO | fails to open |
| FTRC | fails to remain close |
| FTRO | fails to remain open |
| FTR | fails to run |
| FTS | fails to start |

## Acronyms Used in Attachment F

| | |
|---|---|
| GDC | general design criteria |
| GIS | geographic information system |
| HEP | human error probability |
| HHSI | high head safety injection |
| HPI | high pressure injection |
| HRA | human reliability analysis |
| HVAC | heating ventilation and air-conditioning |
| IA | instrument air |
| IPE | individual plant examination |
| IPEEE | individual plant examination – external events |
| IPEM | individual plant evaluation methodology |
| ISLOCA | interfacing system LOCA |
| LERF | large early release frequency |
| LOCA | loss of coolant accident |
| LODC | loss of DC power |
| LOOP | loss of off-site power |
| MAAP | modular accident analysis program |
| MACCS2 | MELCOR accident consequences code system, version 2 |
| MACR | maximum averted cost-risk |
| MCC | motor control center |
| MDAFW | motor driven AFW pump |
| MMACR | modified maximum averted cost-risk |
| MSLB | main steam line break |
| MSPI | Mitigating Systems Performance Index |
| MOV | motor operated valve |
| MSIV | main steam isolation valve |
| NEI | Nuclear Energy Institute |
| NMC | Nuclear Management Company |
| NPSH | net positive suction head |
| NRC | U.S. Nuclear Regulatory Commission |
| NSP | Northern States Power |
| OECR | off-site economic cost risk |
| PINGP | Prairie Island Nuclear Generating Plant |
| PRA | probabilistic risk assessment |
| PORV | pressure operated relief valve |
| PWR | pressurized water reactor |
| PZR | pressurizer |
| RAI | request for additional information |
| RCP | reactor coolant pump |
| RCS | reactor coolant system |
| RDR | real discount rate |
| RHR | residual heat removal |
| RPV | reactor pressure vessel |

## Acronyms Used in Attachment F

| | |
|---|---|
| RRW | risk reduction worth |
| RWST | refueling water storage tank |
| SAMA | severe accident mitigation alternative |
| SBO | station blackout |
| SCBA | self-contained breathing apparatus |
| SETS | set equation transformation system |
| SG | steam generator |
| SGTR | steam generator tube rupture |
| SI | safety injection |
| SQUG | Seismic Qualification Utility Group |
| SRV | safety relief valve |
| SSD | safe shutdown |
| SSE | safe shutdown earthquake |
| SW | service water |
| SWGR | switchgear |
| TD | turbine driven |
| TDAFW | turbine driven auxiliary feedwater pump |
| TS | technical specifications |
| TSC | technical support center |
| USI | unresolved safety issue |
| VCT | volume control tank |
| WOG | Westinghouse Owners Group |

# SEVERE ACCIDENT MITIGATION ALTERNATIVES

The severe accident mitigation alternatives (SAMA) analysis discussed in Section 4.17 of the Environmental Report is presented below.

## F.1 METHODOLOGY

The methodology selected for this analysis involves identifying SAMA candidates that have potential for reducing plant risk and determining whether or not the implementation of those candidates is 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. These values provide a measure of both the likelihood and consequences of a core damage event.

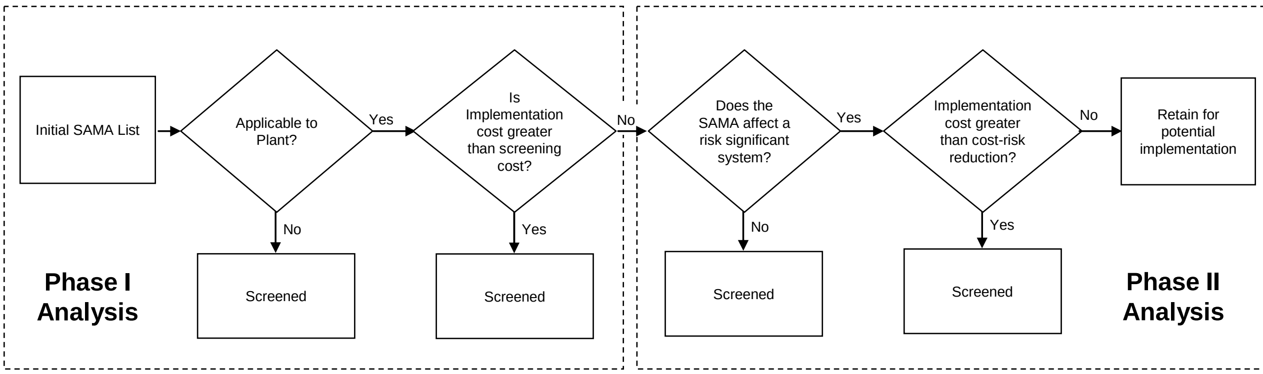
The SAMA process consists of the following steps:

- **PINGP Probabilistic Risk Assessment (PRA) Model** – Use the PINGP Internal Events PRA model as the basis for the analysis (Section F.2). Incorporate External Events contributions as described in Section F.5.1.8.
- **Level 3 PRA Analysis** – Use PINGP Level 1 and 2 Internal Events PRA output and site-specific meteorology, demographic, land use, and emergency response data as input in performing a Level 3 PRA using the MELCOR Accident Consequences Code System Version 2 (MACCS2) (Section F.3). Incorporate External Events contributions as described in Section F.5.1.8.
- **Baseline Risk Monetization** – Use U.S. Nuclear Regulatory Commission (NRC) regulatory analysis techniques to calculate the monetary value of the unmitigated PINGP severe accident risk. This becomes the maximum averted cost-risk that is possible (Section F.4).
- **Phase I SAMA Analysis** – Identify potential SAMA candidates based on the PINGP PRA Individual Plant Examination – External Events (IPEEE), and documentation from the industry and the NRC. Screen out SAMA candidates that are not applicable to the PINGP design or are of low benefit in pressurized water reactors (PWRs) such as PINGP, candidates that have already been implemented at PINGP or whose benefits have been achieved at PINGP using other means, and candidates whose estimated cost exceeds the maximum possible averted cost-risk (Section F.5).
- **Phase II SAMA Analysis** – Calculate the risk reduction attributable to each of the remaining SAMA candidates and compare to a more detailed cost analysis to identify the net cost-benefit. PRA insights are also used to screen SAMA candidates in this phase (Section F.6).

- **Uncertainty 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 summarizes the high level steps of the SAMA process.

**SAMA Screening Process**




Environmental impact statements and environmental reports are prepared using the graded approach in which impacts of greater concern and mitigation measures of greater potential value are studied with correspondingly greater effort and rigor. Accordingly, NMC used screening methods and less detailed feasibility investigative and cost estimation techniques for SAMA candidates having disproportionately high cost or low benefits. High level initial cost estimates for all Phase 1 SAMAs were developed by PINGP project department using plant basis and industry information.

## F.2 PINGP PRA MODEL

The SAMA analysis is based on the 2006 PINGP Level 1 and Level 2, Revision 2.2 PRA models for internal events. The original Individual Plant Examination (IPE) model submitted in 1994 has received a number of technical updates to maintain design fidelity with the operating plant and reflect the latest PRA technology. This section provides an overview of the model revisions and technical upgrades, and provides a basis for conclusion that the PRA scope and quality is sufficient for this application.

The PINGP PRA model peer review was conducted in September 2000. The final report was prepared by Westinghouse, which was the lead in performing the PWR Utility peer assessment. The peer assessment identified five Level A Facts & Observations (F&Os) and 32 Level B F&Os. All A and B Level F&Os have been addressed and closed.

The following subsections provide more detailed information related to the evolution of the PINGP internal events PRA model and the current results. These topics include:

- PRA changes since the IPE
- Level 1 model overview
- Level 2 model overview
- PRA model review summary

Section F.5.1.8 provides a description of the process used to integrate external events contributions into the PINGP SAMA process; therefore, no specific discussion of the external events models is included in this section.

### F.2.1 History of PINGP PRA Model Development

This section describes the IPE and identifies subsequent model changes that were implemented. The IPE, which included both Level 1 and Level 2 PRA analyses for Unit 1 only, is discussed in Section F.2.1.1. Revisions to the Level 1 PRA model since the IPE are discussed in Section F.2.1.2. Revisions to the Level 2 PRA model since the IPE are discussed in Section F.2.1.3. The current Level 1 and Level 2 (Rev. 2.2 (SAMA)), which was used for the SAMA evaluation, is described in Sections F.2.2 and F.2.3, respectively. Detailed descriptions of the changes for each revision are maintained as plant model documentation.

The historical nominal CDF and large early release frequency (LERF) results for PINGP are as follows:

| PINGP Model | Model Revision Date | Unit 1 CDF (per rx-yr) | Unit 2 CDF (per rx-yr) | Unit 1 LERF (per rx-yr) | Unit 2 LERF (per rx-yr) |
|---|---|---|---|---|---|
| IPE (Rev. 0) | 1994 | 5.0E-05 | NA | NA | NA |
| Rev. 1.0 | 1996 | 2.4E-05 | NA | 3.8E-07 | NA |
| Rev. 1.1 | 1999 | 2.35E-05 | NA | 3.8E-07 | NA |
| Rev. 1.2 | 2001 | 2.20E-05 | NA | 6.9E-07 | NA |
| Rev. 2.0 | 2002 | 2.19E-05 | 2.52E-05 | 3.88E-07 | 3.90E-07 |
| Rev. 2.1 | 2005 | 1.47E-05 | 1.63E-05 | 5.74E-07 | 5.74E-07 |
| Rev. 2.2 | 2006 | 9.81E-06 | 1.13E-05 | 5.14E-08 | 1.35E-07 |
| Rev. 2.2 (SAMA) | 2006 | 9.79E-06 | 1.21E-05 | 8.79E-08 | 1.75E-07 |

This section reviews the PRA model development from the IPE to the current Revision 2.2 model, including model enhancements and dominant accident classes.

### F.2.1.1 IPE (Level 1 and Level 2, Revision 0)

The PINGP IPE was submitted to the NRC by letter dated March 1, 1994 to respond to Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities – 10CFR 50.54(f)." The NRC sent requests for additional information (RAI) to Northern States Power Company on December 21, 1995. The NRC accepted the IPE by letter dated May 16, 1997. The NRC letters noted that the IPE submittals met the intent of Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities – 10CFR 50.54(f)", dated November 23, 1988.

The first full-scope PRA analysis done for PINGP was that performed to satisfy the IPE requirements, and was completed in February 1994. This was a study to determine vulnerabilities to severe accidents from at-power operation. It was based on a Level 1 and Level 2 PRA model performed for Unit 1. Unit 2 vulnerabilities were qualitatively evaluated based on the Unit 1 results and consideration of asymmetries in plant design and operation that exist between the units. The study found no vulnerabilities to severe accidents at the PINGP. Previously, a limited-scope Individual Plant Evaluation Methodology (IPEM) analysis was completed in 1992. The IPE PRA analysis started with the models built for the IPEM study, and additional details, including the Level 2 portions, were added to arrive at the full scope analysis. The initial data collection effort for that analysis was performed for the period 1978 – 1987, except for the initiating event frequency analysis, which used plant trip information over the period 1975 – 1987. The IPE is now considered to be Revision 0 of the Level 1 and 2 PRA models.

The core damage frequency (CDF) calculated for the IPE was 5.0E-5/rx-yr. The contributions by initiating event were:

- Loss of coolant accident (LOCAs) (24%);
- Loss of off-site power (LOOP) including station blackout (SBO) (22%);
- Internal Flooding (21%);
- Transients excluding LOOP (19%); and
- Steam generator tube rupture (SGTR) (13%).

LERF was not quantified for the IPE. The total release frequency (the frequency of core damage followed by containment failure) was calculated to be 2.0E-5/rx-yr, giving a conditional containment failure probability (CCFP) of approximately 40% (69% including induced SGTR, which was addressed by an Emergency Operating Procedure (EOP) change almost as soon as the IPE was submitted). The dominant contributors to the CCFP were:

- Late containment failure due to overpressure following early core damage and vessel failure at high pressure (55%); and
- SGTR (35%)
- Other (10%).

### F.2.1.2 Level 1 Model Revisions since the IPE

F.2.1.2.1 <u>Level 1, Revision 1.0</u>

Revision 1.0 of the Unit 1, Level 1 PRA model was completed in 1996. In addition to adding modeling for a few additional balance-of-plant systems (for example, the non-safeguards station air system and the steam dump and circulating water systems), this update included modeling for a number of significant changes to the plant safeguards electrical systems that were not installed at the time of the IPE submittal. Examples include elimination of sub-fed 480V motor control centers (MCCs), division of the two Unit 1 safeguards 480 V AC buses into four buses and relocation of those buses within the plant; and significant reliability upgrades for the DC power system. Component failure and unavailability data for six key systems were updated for the period 1986 through 1995, as were the initiating event frequencies. LOCA frequencies were reanalyzed to make them more plant-specific, using a pipe failure study technique developed by the Electric Power Research Institute (EPRI).

The CDF calculated for the Revision 1.0 PRA model was 2.4E-5/rx-yr. The contributions by initiating event were:

- LOCAs (5%);
- LOOP including SBO (34%);
- Internal Flooding (36%);
- Transients excluding LOOP (10%);
- SGTR (14%); and
- Other (1%).

The decline in the CDF compared with the Revision 1.0 (IPE) model results was primarily due to the development of plant-specific LOCA initiating event frequencies, credit given for the station air to instrument air cross-tie capability, and credit given for an electrical system upgrade and equipment relocation on Unit 1 that effectively eliminated the 480 V safeguards bus dependency on room ventilation.

F.2.1.2.2 <u>Level 1, Revision 1.1</u>

Revision 1.1 of the Unit 1, Level 1 model was completed in 1999. This was essentially the same model as Revision 1.0; however, a single top fault tree approach to the quantification of overall CDF was used, as was a standard truncation level of 1E-10. Previously, the PRA models were quantified using Set Equation Transformation System (SETS) software, which allowed different truncation levels for each individual core damage sequence. The total CDF for the Revision 1.1 model was calculated to be 2.35E-5/rx-yr, and the breakdown of the CDF by initiating event was similar to the Revision 1.0 model.

F.2.1.2.3 <u>Level 1, Revision 1.2</u>

Revision 1.2 of the Unit 1, Level 1 model was completed in 2001. Significant changes were incorporated during this revision. Many of these changes were based on comments received by the Westinghouse Owners Group (WOG) PRA Certification Team Review that took place in September 2000. Changes included:

- New LOCA break size groupings (small LOCA, medium LOCA, large LOCA);
- New LOCA break size frequencies based on generic data from NUREG/CR-5750;
- Update to several initiating event frequencies (LOOP, loss of DC (LODC));
- Inclusion of Offsite Power recovery actions for non-SBO events;
- Creation of initiating event trees for the cooling water system (CL), component cooling system (CC), and Instrument Air systems;
- Power operated relief valve (PORV) LOCA events were added;
- Changes to SBO success criteria (removal of diesel generator recovery);
- Random reactor coolant pump (RCP) Seal Failure initiating event was added;
- Updates to several system fault trees;
- Credit for the pressurizer PORV accumulator;
- Upgrade to the Human Reliability Analysis (key operator actions); and
- The mission time for the emergency diesel generators (EDG) and CL pumps were changed from 6 hours to 24 hours since offsite power recovery is credited.

The component failure rates from the 1995 update were reviewed against generic data. If significant differences were found and there was a large impact on the CDF, the component failure rate was updated. Only a few changes were made. Specifically, EDG D5 and D6 failure and unavailability data were changed based on the limited amount of operating experience available during the update period. Generic failure rates from NUREG/CR-4550 were used for the D5 and D6 EDGs.

The CDF calculated for the Revision 1.2 PRA model was 2.20E-5/rx-yr. The contributions by initiating event were:

- LOOP including SBO (23.9%);
- LOCAs (23.8%);
- Internal Flooding (22.5%);
- SGTR (14.8%); and
- Transients excluding LOOP (15.0%).

There was not a significant change in the overall CDF value compared with the Revision 1.1 model. However, the distribution of the accident sequences has changed significantly. The LOOP contribution decreased due to crediting offsite power recovery for the non-SBO sequences. The SGTR contribution increased due to re-analysis of the human error actions associated with this event. The LOCA contribution increased due to redefining the LOCA break sizes and the use of generic LOCA frequencies. The internal flooding contribution decreased due to crediting the Pressurizer PORV accumulator. The transient contribution increased due to several reasons since it encompasses many initiating events.

- The loss of feedwater transient increased due to changes in the human reliability analysis (HRA). (Key operator actions were re-analyzed based on conditional events, which resulted in a higher probability of failure. A key operator action in the loss of feedwater water transient affected by this includes: establishing feed and bleed conditional on restoring feedwater.);

- The normal transient contribution increased due to the modeling addition of challenging a pressurizer PORV during the transient and resulting in a PORV LOCA; and

- The contribution from a loss of CC and CL transients increased due to the addition of initiating event tree modeling for CL and CC systems.

F.2.1.2.4 Unit 1 and Unit 2 Level 1, Revision 2.0

Level 1, Revision 2.0 PRA model update was performed in order to obtain a working PRA model for Unit 2. Previously, all probabilistic risk analysis for Unit 2 have involved application of the Unit 1 model results, with modifications that attempted to consider the impact of asymmetries between the units. The update was also performed to correct some errors and make some enhancements to the existing Revision 1.2 PRA model. The model update was completed in 2002 and was built upon the Level 1 Revision 1.2 model. Major model changes included with this update are:

- Addition of Unit 2 frontline and support system logic modeling;

- Addition of Unit 2 accident sequence logic modeling;

- Inclusion of CDF and LERF calculations for Unit 2;

- Removal of the boric acid storage tank (BAST) input to the safety injection (SI) pumps suction logic. The primary suction supply is now only the refueling water storage tank (RWST);

- Enhancement of the existing quantification methodology, including incorporation of fault tree-based deletion of mutually exclusive events, including multiple initiating events;

- Modification to the charging pump system fault tree logic to include an operator action to restart the pumps after a LOOP event since they are not included in the sequencer logic;

- Use of the same common cause failure (CCF) event for the residual heat removal (RHR) pump discharge check valves in the injection, recirculation, and shutdown cooling modes;

- A new operator action to prevent load sequencer failure due to loss of cooling to the 4KV safeguards bus rooms (Bus 15, Bus 16, Bus 25, and Bus 26 rooms) were incorporated into the model. In conjunction with this change, a factor for the sequencer failure at elevated temperatures was added to the fault tree logic for the safeguards bus;

- Update to the logic modeling for the supply/exhaust fans 21, 22, 23, 24 which supply air to the Unit 2 safeguards bus rooms. The original modeling assumed that none of the fans were running (but one train is normally running). This modeling change assumed supply/exhaust fan sets 21 and 22 are normally running and supply/exhaust 23 and 24 are in standby. Therefore, the failure to start logic was only included for sets 23 and 24. The CCF to start basic events (BEs) for all four sets was removed from the model; and

- An incorrect and non-conservative mutually exclusive event related to the Screenhouse Flood Zone 2 Initiating event (I-SH2FLD) was removed from the logic. This resulted in an increase in the contribution of the Screenhouse Flood Zone 2 (SH2FLD) event to the overall results.

The CDF calculated for the Unit 1 Revision 2.0 PRA model was 2.19E-5/rx-yr. The contributions by initiating event were:

- LOOP including SBO (26.0%);

- LOCAs (22.4%);

- Internal Flooding (23.2%);

- SGTR (13.2%); and

- Transients excluding LOOP (15.2%).

There was not a significant change in the overall CDF value compared with the Revision 1.2 model. There were some changes in the distribution of the accident sequences. The LOOP contribution increased due to the additional cutsets (with higher probabilities) related to the LOOP event with a failure of the operator to start a charging pump and a loss of the CL pumps which lead to a RCP seal LOCA. The small LOCA contribution decreased (which results in a decrease in the LOCA contribution) due to the removal of the BAST as a supply source to the SI pumps. The SGTR contribution decreased due the new mutually exclusive logic incorporated into the model, specifically related to preventative maintenance on Emergency Diesel Generator (EDGs). The flood contribution increased due to the removal of a mutually exclusive event related to the Screenhouse Flood Zone 2 initiating event.

The CDF calculated for the Unit 2 Revision 2.0 PRA model was 2.52E-5/rx-yr. The contributions by initiating event were:

- LOOP including SBO (25.6%);
- LOCAs (19.4%);
- Internal Flooding (20.1%);
- SGTR (11.8%); and
- Transients excluding LOOP (23.1%).

There is not a previous Unit 2 model to which the results can be compared; however, Unit 2 can be compared to the Unit 1 results. Unit 2 CDF value is higher than the Unit 1 result, due to an increase in the LOOP and LODC Power Train A initiating events. The LOOP initiating event increase is due to the Unit 2 asymmetries associated with the auxiliary feedwater (AFW) system (Unit 2 motor driven AFW (MDAFW) pump powered from Train A verses Unit 1 MDAFW pump powered from Train B) and the emergency diesel generators system (D5 and D6 have higher CCF to start probability verses D1 and D2). These asymmetries result in LOOP event cutsets that have higher probabilities than the Unit 1 results. Also, since the Unit 2 MDAFW pump is powered from Train A, the LODC power Train A event has a larger impact on the Unit 2 CDF results (contributes almost 9% to the overall CDF). This initiator causes the transient portion of the Unit 2 CDF to increase to 23.1% verses 15.2% in the Unit 1 results. The internal flooding event probability remains virtually the same between the Unit 2 and Unit 1 results; however, due to the increase in Unit 2 CDF value, the contribution in the Unit 2 result is lower. This is also the case for the SGTR event.

F.2.1.2.5 Unit 1 and Unit 2 Level 1, Revision 2.1

Revision 2.1 of the Unit 1 and Unit 2, Level 1 model was completed in early 2005. Significant changes were incorporated during this revision. Changes include:

- Update to LOOP initiating event frequency including the addition of consequential LOOP;
- Updates to the RHR, SI, AFW, CL, CC, 125 VDC system, EDG, and instrument power system fault trees;
- Upgrade to the HRA for key operator actions and inclusion of misalignment and miscalibration events;
- Correction to the process used to model pre-initiator latent errors;
- Additional modeling of 120 V AC panel faults;
- Updated failure data for the EDG and AFW systems;
- Updated common cause values for the EDG and AFW systems; and
- Updated internal flooding analysis.

The CDF calculated for the Unit 1 Revision 2.1 PRA model was 1.47E-5/rx-yr. The contributions by initiating event were:

- LOCAs (53.5%);
- Transients excluding LOOP (20.8%);
- SGTR (14.2%);
- LOOP, including SBO (9.8%); and
- Internal flooding (1.7%).

There was a significant change in the overall Unit 1 CDF value compared with the Revision 2.0 model. The distribution of the accident sequences changed significantly. The LOOP contribution decreased due to recalculation of the LOOP initiating event frequency and new EDG common cause and failure data. The LOCA contribution increased due to re-analysis of the human error actions associated with these events. The internal flooding contribution decreased due to reanalysis of the pipe break frequencies and the flows from the break. The transient contribution changed due to several reasons since it encompasses many initiating events:

- Transients increased due to the addition of AFW recirculation line valve failure logic, which was added in the recent fault tree update. This added an extra failure mode for the AFW system;
- The normal transient contribution decreased due to the modeling addition of a factor for the percentage of time that a pressurizer PORV might lift following a transient initiating event; and
- The credit for the pressurizer PORV air accumulator was increased, which reduced the contribution of the loss of instrument air initiating event.

The CDF calculated for the Unit 2 Revision 2.1 PRA model was 1.63E-5/rx-yr. The contributions by initiating event were:

- LOCAs (48.3%);
- Transients excluding LOOP (27.2%);
- SGTR (12.8%);
- LOOP, including SBO (10.2%); and
- Internal flooding (1.5%).

There was a significant change in the overall Unit 2 CDF value compared with the Revision 2.0 model. The distribution of the accident sequences also changed significantly. The LOOP contribution decreased due to recalculation of the LOOP initiating event frequency and new EDG common cause and failure data. The SGTR contribution decreased due to re-analysis of the human error actions associated with this event. The LOCA contribution increased due to re-analysis of the human error actions associated with these events. The internal flooding contribution decreased due to reanalysis of the pipe break frequencies and the flows from the break. The transient contribution changed due to several reasons, as it encompasses many initiating events.

- Transients increased due to the addition of AFW recirculation line valve failure logic, which was added in the recent fault tree update. This added an extra failure mode for the AFW system;
- The normal transient contribution decreased due to the modeling addition of a factor for the percentage of time that a pressurizer PORV might lift following a transient initiating event; and

- The credit for the pressurizer PORV air accumulator was increased which reduced the contribution of the loss of instrument air and loss of A train DC initiating events. As the impact of loss of Train A DC is more significant to Unit 2 than it is to Unit 1 (see Section F.2.1.2.4), this change also reduced the difference in contribution to CDF from Transient events between the units.

#### F.2.1.2.6 Unit 1 and Unit 2 Level 1, Revision 2.2

The most recent major update to the Level 1 PRA models was the Rev. 2.2 model update.

Unit 1 Level 1 Rev. 2.2 Model

The Unit 1 Level 1 Rev. 2.2 model update incorporated a number of model upgrades and enhancements necessary for application of the model to the initial implementation of the Mitigating Systems Performance Index (MSPI) program in 2006, including closure of all remaining open Level B WOG Peer Certification Review findings. The most significant model improvements included:

- Minor updates to the fault tree models for several MSPI systems.
- Update to common cause failure (CCF) parameters using recent data and methodologies.
- Updates to plant and generic failure data, plant maintenance unavailability data, and initiating event frequencies.
- Inclusion of both quantitative and qualitative uncertainty analyses.

In addition, the initiating event frequency update reflected the installation of new steam generators for Unit 1. This change had relatively significant impact on the Level 1 results.

The contribution to core damage frequency (9.81E-06) due to initiating events shows that four initiators contribute 10% or more: Small LOCA – Loop A (25%), Small LOCA – Loop B (25%), Loss of Cooling Water (18%), and Loss of Offsite Power (11%).

The Small LOCA initiating events are the top contributors to the CDF due to their relatively high initiating event frequencies (relative to larger-break LOCAs) and the fact that both methods of mitigation of the event (either Reactor Coolant System (RCS) cool down and depressurization and initiation of RHR shutdown cooling, or transfer to low head Emergency Core Cooling System (ECCS) recirculation) requires operator action. Common cause failures (across both safeguards trains) of component cooling water pumps and valves, and RHR system pumps also are significant contributors to the top Small LOCA sequences.

The CL system (analogous to an emergency service water system at other PWRs) is very important to plant risk at PINGP. CL provides equipment heat removal support for operation of both the high and low pressure ECCS systems. Any event that results in loss of the CL system (a Loss of CL initiating event) also removes the backup means of providing RCP seal cooling. Therefore, on a Loss of CL initiator, failure of seal injection from the Chemical and Volume Control System (CVCS) charging pumps will result in an unrecoverable RCP seal LOCA.

Loss of offsite AC power is significant due to its relatively high frequency and reliance upon the site emergency diesel generators (EDGs) and their support systems. The EDGs are complex machines that have many subsystems and have relatively high random failure rates (compared to other plant components, i.e., motor-operated pumps or valves, etc.). Typically, core damage sequences following this initiating event are a result of an eventual station blackout (SBO) condition, subsequent RCP seal failures and resulting RCS leakage without makeup capability. In some cutsets, power may be lost on one train, and equipment fails on the energized train, causing a loss of a critical function. Credit is taken for recovery of offsite power based on industry experience with the duration of loss of offsite power events. PINGP has the ability to manually cross-tie same-train 4kV buses across units (from the control room), and the EDGs have the capability to handle the loads that would be expected during a dual-unit LOOP. In addition, the Unit 1 and Unit 2 EDGs have different designs and manufacturers, and require different systems for cooling. Therefore, the contribution due to SBO is not as significant at PINGP as at some other PWRs.

<u>Unit 2 Level 1 Rev. 2.2 Model</u>

The Unit 2 Level 1 Rev. 2.2 model update incorporated all of the model upgrades and enhancements described above for the Unit 1 model, including all of those necessary to implement the MSPI program for Unit 2 in 2006, and closure of all remaining open Level B WOG Peer Certification Review findings. The only significant difference between the update for Unit 1 and the update for Unit 2 was that the initiating event frequency update does not reflect an installation of new steam generators for Unit 2. Steam generator replacement is planned for Unit 2 in 2013.

Unit 1 and Unit 2 are near-mirror images of each other with respect to design and operation. Therefore, as expected, the Level 1 PRA results (CDF and contributions by initiating event) are very similar between the units. The contribution to core damage frequency (1.13E-05) due to initiating events shows that four initiators contribute 10% or more: Small LOCA – Loop A (21%), Small LOCA – Loop B (21%), Loss of Cooling Water (16%), and Loss of Offsite Power (10%). The discussion presented in this section of each of these top contributors to the Unit 1 CDF applies to the Unit 2 results as well.

The most significant asymmetries between the CDF results for Unit 1 and Unit 2 are in the contributions from the SGTR and Loss of Train A DC initiating events. The SGTR contribution for Unit 2 is significantly larger than it is for Unit 1 (10.0% of the total CDF vs. 2.0%, respectively), due to the fact that the steam generators in Unit 1 have undergone replacement recently while Unit 2 is still using its original steam generators. The Loss of Train A DC initiating event is more significant to the Unit 2 results (3.5% of the total CDF) than to the Unit 1 results (0.4% of the total CDF) due to the fact that DC control power for operation of the motor-driven Auxiliary Feedwater pump on Unit 2 is supplied from Train A, whereas control power for operation of the Unit 1 motor-driven AFW pump is supplied from Train B DC. Both units experience a reactor trip with loss of main feedwater on a loss of Train A DC (no loss of main feedwater on loss of Train B DC). Therefore, since AFW is required for secondary heat removal when main feedwater is lost, the Loss of Train A DC initiating event is more severe for Unit 2 than for Unit 1.

F.2.1.2.7 Unit 1 and Unit 2 Level 1, Revision 2.2 (SAMA)

The latest version of the Unit 1 and Unit 2 Level 1 PRA is the Rev. 2.2 model (SAMA). This was the version of the model used for the SAMA evaluation supporting this LRA submittal. For a discussion of the Level 1 Rev. 2.2 model (SAMA), see Section F.2.2.

### F.2.1.3 Level 2 Model Revisions since the IPE

F.2.1.3.1 Level 2, Revision 1.0

Revision 1.0 of the Unit 1, Level 2 PRA model was completed in 1999, and was built upon the Level 1 Revision 1.0 model. In addition to the changes incorporated in the revision to the Level 1 model, the Level 2 update reflected credit for the potential for hot leg creep rupture phenomenon to facilitate vessel failure at low pressure for early core damage sequences and credit for a change to the emergency procedures that greatly reduced the risk from induced steam generator (SG) tube creep rupture events (these events were not modeled in the Revision 1.0 analysis). Also, credit for containment spray (CS) recirculation was removed from the model, since procedural guidance for operator initiation of the system in the EOPs was removed (based on a licensing-basis calculation that showed that containment pressure would be below the threshold requiring CS recirculation operation for any analyzed event after the RWST had reached low-low level).

The total release frequency (the frequency of core damage followed by containment failure) was calculated to be 8.8E-6/rx-yr, giving a conditional containment failure probability (CCFP) of approximately 38%.

The decline in the total release frequency was primarily due to the decline in the Level 1 CDF (from the Revision 0 to the Revision 1 analysis). The decline was slightly less than that seen in the CDF itself due to the relatively large CDF contribution to both measures from internal flooding events. The contribution of flooding events to the total release frequency remained relatively constant at about 35% (9E-6).

LERF was quantified for the Revision 1 Level 2 model. Early core damage sequences involving containment bypass (SGTR and interfacing system LOCA (ISLOCA) sequences) and containment isolation failure were considered to be those with the potential to produce a large early release. The calculated LERF was 3.8E-7/rx-yr. The contributors to the LERF by initiating event (sub-bullets provide a discussion of dominant sequences within these categories) were:

- ISLOCA (58% of LERF),
    - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction motor operated valves (MOVs) followed by operator failure to cool down and depressurize the reactor to limit RHR pump seal leakage. (41% of LERF),
    - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs, or rupture of two series SI injection check valves, or one SI injection check valve and the RHR shutdown cooling isolation MOV, followed by rupture of the low pressure RHR piping outside containment. (17% of LERF);
- SGTR (15% of LERF),
    - SGTR followed by common cause failure of either the SI pumps (to start or run) or the RWST to SI suction MOVs to open, followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions. (14% of LERF); and
- Transient or LOCA core damage sequences followed by early containment failure (typically through hydrogen combustion) (25% of LERF),
    - AFW Pump/Instrument Air Compressor room internal flood (15% of LERF),
    - RCP seal LOCA involving loss of CL and Train A 4kV AC power (5% of LERF),
    - Loss of secondary heat sink with failure of operator action to perform bleed and feed operation (3% of LERF), and
    - Medium or large LOCA with failure of Emergency Core Cooling System (ECCS) recirculation (1% of LERF).
- Transient or LOCA core damage sequences followed by other early containment failure mechanisms (2% of LERF),

F.2.1.3.2 Level 2, Revision 1.1

No Level 2 or LERF model was developed with this designation (no update to the Level 2 models or to LERF was performed which used the Level 1, Revision 1.1 model as input). The basis for this was the nearly identical nature of the Revision 1.0 and Revision 1.1 Level 1 models, that is, no significant difference in the Level 2 results could exist based solely on the move to the Revision 1.1 model.

F.2.1.3.3 Level 2, Revision 1.2

A full Level 2 revision to correspond with the Level 1, Revision 1.2 model was not performed. However, the LERF results were updated based on the Level 1, Revision 1.2 model, and changes to the LERF calculation were made.

One change made to the Level 1 model incorporated in Revision 1.2 had a significant impact on the LERF results. The human error probability (HEP) for the failure of the operator to cool down and depressurize the RCS to shutdown cooling following a SGTR, originally a screening value with a very low probability, was increased by an order of magnitude. This change shifted the majority of the LERF contribution to SGTR sequences (from Interfacing System LOCA (ISLOCA) sequences).

Other than the changes to the underlying Level 1 model, the following changes were made to the LERF calculation itself:

1. Failure of containment isolation was modeled using a fault tree (FT) model for each unscreened containment penetration from the previous analysis. The previous LERF analysis used a point value estimate for the failure of containment isolation.

2. Core damage sequences involving early containment failure but without containment bypass (from the full Level 2 analysis) were excluded from the LERF result. As stated previously, a full Level 2 model update based on the Level 1 Revision 1.2 model was not performed. In addition, these sequences had been conservatively added to the LERF calculation in the absence of certainty about whether they met an industry standard definition of large, early release that was still in development. The American Society of Mechanical Engineers (ASME) PRA Standard defines a large early release as “the rapid, unmitigated release of airborne fission products from the containment to the environment occurring before the effective implementation of offsite emergency response and protective actions” (ASME 2005). Under this definition, it is not clear that these early containment failure sequences actually would lead to large early releases, since containment is not directly bypassed. The IPE source term analysis showed only the containment bypass events (induced-SGTR, ISLOCA) to result in the highest releases of volatile (non-noble gas) radionuclides.

SGTR events also involved large releases of volatiles, but was considered to be a late release. Containment isolation failure sequences involved early releases but the magnitude of the volatiles was categorized as medium. Also, the majority of these sequences were assumed to lead to early containment failure due to very conservative treatment of the hydrogen combustion phenomenon. However, position papers created for the IPE conclude that, even assuming worst-case hydrogen production conditions post core damage, pressures developed within the containment following a detonation of the hydrogen would not approach the ultimate failure pressure of the containment shell itself.

Evidence also exists that ignition sources energetic enough for detonation of the hydrogen do not exist within the containment. Even if containment failure were to occur by this mechanism, it is likely that the timing of the failure would be later than that specified in the LERF definition (time for implementation of protective action recommendations from the emergency plan response would be available due to the additional time required to pressurize containment to its ultimate failure pressure).

Therefore, the non-bypass early containment failure sequences were excluded from the LERF calculation (SGTR and containment isolation failure sequences were left in).

The calculated LERF for Revision 1.2 was 6.9E-7/rx-yr. The contributors to the LERF by initiating event were (sub-bullets provide a discussion of dominant sequences within these categories):

- SGTR (87% of LERF),
  - SGTR followed by common cause failure of either the SI pumps (to start or run) or the RWST to SI suction MOVs to open, followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions. (69% of LERF);
- ISLOCA (13% of LERF),
  - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs, or rupture of two series SI injection check valves, or one SI injection check valve and the RHR shutdown cooling isolation MOV, followed by rupture of the low pressure RHR piping outside containment. (9% of LERF),
  - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs followed by operator failure to cool down and depressurize the reactor to limit RHR pump seal leakage. (4% of LERF); and
- Other core damage sequences followed by failure of containment isolation (<1 % of LERF)

F.2.1.3.4 Level 2, Revision 2.0

A full Level 2 revision to correspond with the Level 1, Revision 2.0 model was not performed. However, the LERF results were updated based on the Level 1, Revision 2.0 model, and changes to the LERF calculation were made.

One change made to the Level 1 model incorporated in Revision 2.0 had a significant impact on the LERF results. The removal of the BAST as a supply source to the SI pump suction logic significantly reduced the contribution of the SGTR event to the LERF result.

Other than the changes to the underlying Level 1 model, the following changes were made to the LERF calculation itself:

- The containment isolation failure logic modeling (gate 1CIF and 2CIF) was expanded to include catastrophic leakage from the equipment hatch door, the fuel transfer tube, and open personnel or maintenance airlock doors.

The calculated LERF for the Unit 1 Revision 2.0 was 3.88E-7/rx-yr. The contributors to the LERF by initiating event were (sub-bullets provide a discussion of dominant sequences within these categories):

- SGTR (76% of LERF),
    - o STGR followed by common cause failure of the SI pumps (to start or run), followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions. (28% of LERF);
- ISLOCA (23% of LERF),
    - o Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs, rupture of two series SI injection check valves, or one SI injection check valve and the RHR shutdown cooling isolation MOV, followed by rupture of the low pressure RHR piping outside containment. (11% of LERF),
    - o Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs followed by operator failure to cool down and depressurize the reactor to limit RHR pump seal leakage. (7% of LERF); and
- Other core damage sequences followed by failure of containment isolation (1% of LERF)

The calculated LERF for Unit 2 Revision 2.0 was 3.90E-7/rx-yr. The contributors to the LERF by initiating event were (sub-bullets provide a discussion of dominant sequences within these categories):

- SGTR (76% of LERF),

- STGR followed by common cause failure of the SI pumps (to start or run), followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions. (28% of LERF);

- ISLOCA (23% of LERF),
    - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs, or rupture of two series SI injection check valves, or one SI injection check valve and the RHR shutdown cooling isolation MOV, followed by rupture of the low pressure RHR piping outside containment. (11% of LERF),
    - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs followed by operator failure to cool down and depressurize the reactor to limit RHR pump seal leakage. (7% of LERF); and
- Other core damage sequences followed by failure of containment isolation (1% of LERF)

F.2.1.3.5 Level 2, Revision 2.1

A full Level 2 revision to correspond with the Level 1, Revision 2.1 model was not performed. However, an update to the LERF results based on the Level 1, Revision 2.1 model was performed. Other than the changes to the underlying Level 1 model, there were no changes made to the LERF model.

The calculated LERF for the Unit 1 Revision 2.1 was 5.74E-7/rx-yr. The contributors to the LERF by initiating event were (sub-bullets provide a discussion of dominant sequences within these categories):

- SGTR (54% of LERF),
    - STGR followed by common cause failure of the SI pumps (to start or run), followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions; and
- ISLOCA (45% of LERF),
    - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs followed by operator failure to cool down and depressurize the reactor to limit RHR pump seal leakage, and
    - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs, or rupture of two series SI injection check valves, or one SI injection check valve and the RHR shutdown cooling isolation MOV, followed by rupture of the low pressure RHR piping outside containment.
- Other core damage sequences followed by failure of containment isolation (<1% of LERF)

The resulting LERF is higher than the Revision 2.0 model because the HRA updates for the Revision 2.1 model resulted in a higher failure probability for the operator actions to cool down and depressurize the RCS. This resulted in a higher contribution from the ISLOCA sequences, and consequentially a higher LERF value.

The calculated LERF for the Unit 2 Revision 2.1 was 5.74E-7/rx-yr. The dominant contributors to the LERF were:

- SGTR (54% of LERF),
  - o STGR followed by common cause failure of the SI pumps (to start or run), followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions; and
- ISLOCA (45% of LERF),
  - o Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs followed by operator failure to cool down and depressurize the reactor to limit RHR pump seal leakage, and
  - o Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs, or rupture of two series SI injection check valves, or one SI injection check valve and the RHR shutdown cooling isolation MOV, followed by rupture of the low pressure RHR piping outside containment.
- Other core damage sequences followed by failure of containment isolation (<1% of LERF)

The resulting LERF is higher than the Revision 2.0 model because the recent HRA updates for the Revision 2.1 model resulted in a higher failure probability for the operator actions to cooldown and depressurize the RCS. This resulted in a higher contribution from the ISLOCA sequences and consequentially, a higher LERF value.

#### F.2.1.3.6 Level 2, Revision 2.2

A full Level 2 revision to correspond with the Level 1, Revision 2.2 model was not performed. However, an update to the LERF results based on the Level 1, Revision 2.1 model was performed. Other than the changes to the underlying Level 1 model, there were no changes made to the LERF model.

The calculated LERF for the Unit 1 Revision 2.2 was 5.14E-8/rx-yr. The dominant contributors to the LERF were:

- ISLOCA (63% of LERF),
  - o Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs, or rupture of two series SI injection check valves, or one SI injection check valve

and the RHR shutdown cooling isolation MOV, followed by rupture of the low pressure RHR piping outside containment, and
 - o Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs followed by operator failure to cool down and depressurize the reactor to limit RHR pump seal leakage.

- SGTR (34% of LERF),
  - o STGR followed by common cause failure of the CC pumps (to start or run), followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions; and
  - o STGR followed by common cause failure of the SI pumps (to start or run), followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions
- Other core damage sequences followed by failure of containment isolation (3% of LERF)

The resulting LERF is lower than the Revision 2.1 model because the several factors including a decrease in the SGTR frequency to account for the new steam generator installation. In addition, the Rev 2.2 model updated the component failure rates and common cause factors which resulted in a decrease in the failure rate associated with catastrophic leaks on containment penetration motor valves, and common cause multipliers associated with the RHR heat exchanger cooling water supply motor valves, RHR pumps and SI pumps, and Containment Isolation (CI) control valves. These components are important for mitigating LERF consequences.

The calculated LERF for the Unit 2 Revision 2.2 was 1.35E-7/rx-yr. The dominant contributors to the LERF were:

- SGTR (75% of LERF),
  - o SGTR followed by common cause failure of the SI pumps (to start or run), followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions; and
- ISLOCA (24% of LERF),
  - o Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs followed by operator failure to cool down and depressurize the reactor to limit RHR pump seal leakage, and
  - o Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs, or rupture of two series SI injection check valves, or one SI injection check valve and the RHR shutdown cooling isolation MOV, followed by rupture of the low pressure RHR piping outside containment.
- Other core damage sequences followed by failure of containment isolation (1% of

LERF)

The resulting LERF is lower than the Revision 2.1 model because of several factors, including a decrease to the SGTR frequency due to an updated Bayesian analysis. In addition, the Rev 2.2 model updated the component failure rates and common cause factors which resulted in a decrease in the failure rate associated with catastrophic leaks on containment penetration motor valves, and common cause multipliers associated with the RHR heat exchanger cooling water supply motor valves, RHR pumps and SI pumps, and Containment Isolation (CI) control valves. These components are important for mitigating LERF consequences.

The most significant asymmetry between the LERF results for Unit 1 and Unit 2 is in the contribution from the SGTR initiating event. The SGTR contribution is significantly larger for Unit 2 than it is for Unit 1 (75% of the total LERF vs. 34%, respectively), due to the fact that the steam generators in Unit 1 have undergone replacement recently while Unit 2 is still using its original steam generators.

#### F.2.1.3.7 <u>Level 2, Revision 2.2 (SAMA)</u>

The current version of the Unit 1 and Unit 2 Level 2 PRA is the Rev. 2.2 model (SAMA). This revision, an update of the full Level 2 analysis, was the version of the model used for the SAMA evaluation supporting this LAR submittal. For a discussion of the Rev. 2.2 Level 2 model (SAMA), see Section F.2.3.

## F.2.2 PINGP Level 1 PRA Model

The SAMA analysis is based on the PINGP Level 1 PRA Model of Record developed in 2006 (Rev. 2.2). As described in Section F.2.1.2.6, this model includes the changes and analysis that were required to support the Unit 1 steam generator replacement that occurred in 2004. In addition, all Level A and B Westinghouse Peer Certification comments (F&Os) have been dispositioned and those requiring model and/or documentation changes have been addressed with the issuance of this model.

In addition to the Level 1, Rev. 2.2 changes described in Section F.2.1.2.6, two additional changes were made to support the SAMA analysis (described in Sections F.2.2.1 and F.2.2.2). The Level 1 PRA model used for the SAMA evaluation is called the “Rev. 2.2 (SAMA)” model.

### F.2.2.1 Unit 1, Level 1 Rev. 2.2 (SAMA)

The latest version of the Unit 1 Level 1 PRA is the Rev. 2.2 model (SAMA). This was the version of the model used for the SAMA evaluation supporting this LRA submittal. This model included one model correction that had a slight impact on Unit 1 CDF (final CDF decreased approximately 2E-8/yr, to 9.79E-6/yr). The correction was made to the Level 1 core damage sequence success logic for the Small LOCA event. As a result, a small number of illogical cutsets (previously retained) were deleted in the CDF metric for the SAMA model quantification.

The changes for Unit 1 only slightly alter the core damage frequency results by initiating event from that described for the Rev. 2.2 model in Section F.2.1.2.6. Four initiators contribute 10% or more: Small LOCA – Loop A (25%), Small LOCA – Loop B (25%), Loss of Cooling Water (18%), and Loss of Offsite Power (11%). This is shown graphically in Figure F.2-1.

The balance of the discussion provided in Section F.2.1.2.6 is also representative of the SAMA model results for Unit 1.

### F.2.2.2 Unit 2, Level 1 Rev. 2.2 (SAMA)

The latest version of the Unit 2 Level 1 PRA is the Rev. 2.2 model (SAMA). This was the version of the model used for the SAMA evaluation supporting this LRA submittal. In addition to the model correction described above for Unit 1 (Section F.2.2.1), this model included one additional correction that had a slight impact on Unit 2 CDF (final CDF increased approximately 8E-7/yr, to 1.21E-5/yr).

The changes for Unit 2 only slightly alter the core damage frequency results by initiating event from that described for the Rev 2.2 model in Section F.2.1.2.6. Four initiators contribute 10% or more: Small LOCA – Loop A (22%), Small LOCA – Loop B (22%), Loss of Cooling Water (15%), and Loss of Offsite Power (10%). On Unit 2, the SGTR initiating events for Loop A (5%) and Loop B (5%) (together) also contribute 10% to the CDF. This is shown graphically in Figure F.2-2. The balance of the discussion provided in Section F.2.1.2.6 above is also representative of the SAMA model results for Unit 2.

Note that, at the time of the Rev. 2.2 model update, containment sump strainer modifications to address G.L. 2004-02 on Unit 2 had not been completed. These modifications have now been completed. Section F.7.4 discusses the results of an analysis to address the sensitivity of the SAMA results to this plant configuration change.

### F.2.3 PINGP Level 2 PRA Model

The SAMA analysis is based on the PINGP Level 2 PRA Model of Record (Level 2 Revision 2.2 (SAMA)) that was developed in 2006. This model is an update of the Level 2, Rev. 1 model performed in 1999, and incorporates changes and analysis that were required to support the Level 1 Rev. 2.2 (SAMA) model updates. In addition, all PINGP Level A and B PRA model Westinghouse Peer Certification comments (F&Os) have been dispositioned and those requiring model and/or documentation changes have been addressed with the issuance of this model.

The containment response analysis (Level 2) evaluates the best estimate performance of the containment during a severe accident. The status of the containment safeguards systems is modeled to account for the effects of containment cooling and isolation. This model accounts for core damage sequences that cause a direct bypass of containment, such as a SGTR or inter-system LOCA. The design pressure of the PINGP containment is 46 psig, but based on a probabilistic evaluation of the containment structure, the mean expected failure pressure is 150 psig (165 psia). The 5% lower bound and 95% upper bound failure pressures are 136 psia and 191 psia, respectively. Thus the containment is relatively robust against failure due to overpressure.

The dynamic response to core debris expulsion as it is transported through the vessel cavity and through other containment compartments is analyzed to estimate the effects of direct containment heating and subsequent containment pressurization. Other severe accident effects, such as hydrogen generation and ignition are evaluated as to their likelihood in each sequence. The Level 2 analysis is used to predict the ability of the containment to mitigate severe accident challenges and, in the case of failure, to predict the timing of containment failure and subsequent radionuclide release for each release category.

As is typical of most large dry containments, the PINGP containment is robust against severe accident challenges, such as hydrogen burns and the effects of high pressure melt ejection. These failure mechanisms are calculated to produce pressure increases within the capability of the PINGP containment structure, and so are not likely to cause containment failure.

It is important to define a special group of release categories where the radionuclide release from the containment would occur prior to the initiation of evacuation planning and is of such a magnitude that the potential for some measurable health effects cannot be precluded. This variety of release is typically measured by the LERF. A large early release from the containment can occur from containment breach due to containment failure at the time of reactor vessel break or a bypass of containment due to such events as a steam generator tube rupture (SGTR), ISLOCA, or containment isolation failure. Typically it involves the rapid, unscrubbed release of airborne aerosol fission products to the environment with core damage occurring, or a containment failure pathway of sufficient size to release the contents of the containment within one hour, which occurs before or within 4 hours of vessel breach. One definition of LERF proposed in NUREG/CR-6595 is the “frequency of early failure and bypass containment failure modes that have a release fraction of iodine equal to or greater than about 10%”. Based on MAAP source term analysis for PINGP, the only release categories that meet these requirements include core damage with containment bypass scenarios (SGTR and ISLOCA). Pressure- and temperature-induced SGTR sequences are included in the LERF definition, but SGTR sequences that leads to late core damage following SG overfill are not included due to the long time available prior to depletion of the RWST and core uncovery. In addition to these scenarios, PINGP includes the frequencies of containment isolation failure release categories in the definition of LERF, as they represent scenarios involving core damage with early containment bypass.

### F.2.3.1 Unit 1, Level 2 Rev. 2.2 (SAMA)

The large early release frequency (LERF) for unit 1 is calculated to be 8.79E-8 per year. Like the CDF, this numeric measure is used when applying the PRA results by evaluating relative changes, and together with CDF, are the two primary "risk metrics" used in describing PRA quantification results.

The dominant contributors to the LERF by initiating event were ISLOCA (36.7%), Small LOCAs (25.4%), and SGTR (18.5%). This is shown graphically in Figure F.2-3. The Small LOCA initiating event category (the dominant Level 1 initiator category) is more significant in the Rev. 2.2 SAMA model LERF analysis due to inclusion of induced SGTR modeling as an additional LERF contributor in this update. The balance of the discussion provided in Section F.2.1.3.6 is also representative of the SAMA model LERF results for Unit 1. The LERF must be understood in context of the overall Level 2 results. The conditional containment failure probability (CCFP) for Unit 1 is 0.26. This equates to a containment success probability of 0.74. Figure F.2-5 summarizes the contribution of the containment failure modes to the Unit 1 CCFP. Early containment bypass failures, occurring near the time of core damage and reactor vessel failure, and resulting in large fission product releases, represent only about 3% of the CCFP. Other non-bypass but early containment failure release classes make up only an additional 2% of the CCFP. Late containment bypass from slow developing SGTR scenarios (release category GLH) make up about 7% of the CCFP. The large majority of containment failure sequences are late failures that involve a significant time delay between core damage and containment failure of up to several days. Significant time is available to implement emergency measures to protect the public for the most likely severe accident scenarios (>90% of core damage sequences), significant time is available to implement emergency measures to protect the public. The amount of time available to implement emergency measures is significant when evaluating plant conditions using Level 2 results. For cases involving late failure of containment, the dominant cause of containment breach involves core damage sequences that end with the RWST being depleted and no long-term decay heat removal mechanism available. For these sequences, the containment fails due to gradual overpressure of the containment due to steam and non-condensable gas generation. Another significant cause of late containment failure is basemat failure resulting from long-term (greater than 3 days) concrete ablation by molten core material.

### F.2.3.2 Unit 2, Level 2 Rev. 2.2 (SAMA)

The Unit 2 large early release frequency (LERF) is calculated to be 1.75E-7 per year. The Unit 2 LERF is larger than the Unit 1 LERF by about a factor of 2, primarily due to the assumed slightly higher potential for a SGTR initiating event on Unit 2. The Unit 1 steam generator replacement project was completed in 2004, while the Unit 2 steam generator replacement is planned for 2013.

The dominant contributors to the LERF by initiating event were SGTR (56.4%), ISLOCA (18.4%) and Small LOCAs (14.4%). This is shown graphically in Figure F.2-4. The Small LOCA initiating event category (the dominant Level 1 initiator category) is more significant in the Rev. 2.2 SAMA model LERF analysis due to inclusion of induced SGTR modeling as an additional LERF contributor in this update. The balance of the discussion provided in Section F.2.1.3.6 is also representative of the SAMA model LERF results for Unit 2.

The conditional containment failure probability (CCFP) for Unit 2 is 0.30. This equates to a containment success probability of 0.70. Figure F.2-6 summarizes the contribution of the containment failure modes, which make up the Unit 2 CCFP. The fraction of the CCFP from early containment bypass failures, about 5%, is slightly higher than for Unit 1 due to the higher SGTR initiating event frequency on Unit 2. The higher SGTR initiating event frequency for Unit 2 results also in a significantly larger fraction of the CCFP associated with late containment bypass sequences (28% vs. 7% for Unit 1). The remaining portion of the late containment failure results are similar to that discussed above for Unit 1.

### F.2.4 PINGP Level 2 Release Categories

The solution of the numerous event trees results in the generation of a large number of accident sequences. Once developed, the accident sequences must be propagated through the containment safeguards assessment and the containment event tree to develop release categories. To reduce the burden on the analyst, the accident sequences can be grouped, commonly referred to as binning, into accident sequence categories.

The method of binning the accident sequences is much like that used to categorize the transient initiating events. A set of parameters is identified that can be used to define unique accident sequence classes. These parameters are typically defined based on the needs of the containment analysis. For example, one parameter commonly used in the binning process is the RCS pressure (high or low) at the time of core damage. The RCS pressure parameter is critical in the progression of potential Level 2 containment accident sequences. For example, a high pressure core melt sequence was defined as the primary system pressure being high enough to entrain the core debris out of the cavity upon vessel failure. A low pressure sequence was defined as the primary system pressure being low enough at vessel failure for the core debris to be retained in the cavity. This parameter, therefore, is typically chosen for binning accident sequences. Once the important parameters are identified the next step is to determine the physically possible combinations of the parameters. Each combination of the parameters defines an accident class or core damage bin (CDB).

Once the CDBs are finalized, the Level 1 event tree accident sequences are assigned to them by comparing the CDB parameters and the cutsets that comprise the specific accident sequences.

CDB information must be combined with the status of the containment safeguards systems to develop a complete accident sequence definition for containment assessment. This is done in the Containment Event Trees (CETs). The CETs provide a means for interfacing the core damage (Level 1) model with the containment safeguards functions, and the containment phenomenological processes. The CETs address the status of the containment systems to complete the system-level information needed by the Level 2 PRA analyst. The status of the containment systems is important in determining containment pressure challenges, source term composition, and other physical parameters associated with the Level 2 PRA. Additionally, the use of a CET that incorporates fault tree and event tree models allows the core damage sequence cutsets to be linked directly to the CET. The direct linking of the system model results in containment and core safety system dependencies being identified and explicitly addressed.

The CETs provide a convenient method to identify the various possible outcomes resulting from different combinations of CDBs, containment systems status, and containment phenomenological effects. The CET sequences are solved to determine the conditional probabilities for each CET outcome, each of which are mapped to specific release categories. Each of the release categories are given 4-letter designations identifying whether or not the reactor pressure vessel failed and at what pressure, whether or not the containment failed and by what mechanism, and timing of containment failure (if it occurred). Summing all the CET sequence frequencies for a release category class determines the frequency for that release category.

The CET end states correspond to the outcome of possible severe accident sequences. Each end point defines a different containment state with an associated radionuclide release. Simplifications can be attained by grouping sequences with similar release characteristics into release categories (at PINGP the CET end states and the release categories have similar 4-letter designators, although some release categories are considered bounding for other categories with respect to source term). A set of bounding release categories is defined such that all accidents assigned to the same category are assumed to have the same set of release fractions.

The main characteristics used to define the release categories are release energy, containment isolation failure size, timing of the release, and isotopic consumption.

Specific Modular Accident Analysis Program (MAAP) sequences were developed to mimic CET end states and the estimated releases determined. Like CET end states were grouped to minimize the number of MAAP sequences required. The MAAP code outputs fission product data which is used to group similar sequences according to time of release and radionuclide release. Of the 18 release categories, including 3 release categories in which the containment has remained intact (release of fission products is through containment leakage only), 10 bounding categories for source term analysis were identified.

The following paragraphs define each release category and related assumptions are defined in the following subsections. In addition, those release categories that were grouped with other, bounding categories for source term analysis are identified (note that those release categories calculated to have near-zero frequencies of occurrence are not discussed separately below).

### F.2.4.1 Containment Intact (Release Categories X-XX-X, L-XX-X, H-XX-X)

These release categories represent the accident sequences in which the containment remains intact. The source term for this type of sequence is very small and limited to the containment design leakage rate. Category H-XX-X was selected as the bounding category and a representative sequence was chosen from that category for X-XX-X, L-XX-X and H-XX-X source term analysis. The total baseline frequency for these release categories is 7.28E-06/yr for Unit 1 and 8.52E-06/yr for Unit 2.

### F.2.4.2 Release Category L-CC-L

This release category includes core damage sequences that are not arrested in-vessel (the core goes ex-vessel at low reactor pressure) and ex-vessel injection to quench the debris in the reactor cavity fails. Containment failure on overpressure occurs as a result of basemat penetration from core concrete interaction. The total baseline frequency for this release category is 2.82E-07/yr for Unit 1 and 3.39E-07/yr for Unit 2.

### F.2.4.3 Release Category L-CI-E

This release category includes core damage sequences where the reactor vessel fails at low reactor pressure, with failure of containment isolation. Core damage from small LOCA sequences with failure of ECCS injection or recirculation dominates this release category. Successful hot leg creep rupture allows the debris to exit the vessel at low pressure. The release from the containment is scrubbed by either the containment sprays or a pool of water over the core debris. The total baseline frequency for this release category is 1.85E-10/yr for both Unit 1 and Unit 2.

### F.2.4.4 Release Category L-DH-L

This release category includes core damage sequences in where the reactor vessel fails at low reactor pressure, with overpressure failure of containment due to steam generation and failure of containment pressure control (failure of containment fan coil units or ECCS recirculation to remove decay heat). Core damage from RCP seal LOCA sequences with failure of ECCS recirculation dominates this release category. Successful hot leg creep rupture allows the debris to exit the vessel at low pressure. The release from the containment is scrubbed by either containment spray or a pool of water over the core debris. The total baseline frequency for this release category is 1.92E-06/yr for Unit 1 and 1.97E-06/yr for Unit 2.

#### F.2.4.5 Release Category L-H2-E

This release category is similar to release category L-DH-L, except that the containment fails from early containment failure modes such as hydrogen combustion or in-vessel steam explosion with the reactor at low pressure. Core damage from RCP seal LOCA or small LOCA sequences with failure of ECCS recirculation dominates this release category. The total baseline frequency for this release category is 2.23E-08/yr for Unit 1 and 2.49E-08/yr for Unit 2.

#### F.2.4.6 Release Category H-DH-L

This category is similar to L-DH-L, except that hot leg creep rupture is not successful and the core debris exits the vessel at high pressure. Containment fails very late on overpressure due to steam generation and failure of containment pressure control (failure of containment fan coil units and ECCS recirculation to remove decay heat). The total baseline frequency for this release category is 3.09E-08/yr for Unit 1 and 3.14E-08/yr for Unit 2.

#### F.2.4.7 Release Category H-H2-E

This release category includes core damage sequences in where the reactor vessel fails at high reactor pressure, with overpressure failure of containment from early containment failure modes such as hydrogen combustion. ECCS injection is not successful for these sequences, and hot leg creep rupture does not successfully depressurize the reactor prior to vessel failure. The total baseline frequency for this release category is 2.32E-11/yr for both Unit 1 and Unit 2.

#### F.2.4.8 Release Category H-OT-L

This release category includes core damage sequences in which the reactor vessel fails at high reactor pressure, with late overtemperature or overpressure failure of containment due to inability to cool debris that may have relocated to the upper parts of containment. Neither ECCS injection nor RWST injection to the containment through containment spray is available throughout this scenario. The total baseline frequency for this release category is 4.89E-09/yr for Unit 1 and 5.87E-09/yr for Unit 2.

#### F.2.4.9 Release Category X-CI-E

This release category includes core damage sequences where containment isolation fails, but the reactor vessel does not fail (core damage is arrested in vessel due to successful ex-vessel cooling), leading to a lower source term than the other containment isolation failure release categories. The source term for this category is bounded by the L-CI-E case. The total baseline frequency for this release category is 6.55E-10/yr for Unit 1 and 7.32E-10/yr for Unit 2.

### F.2.4.10 Release Category X-H2-E

This release category is similar to category L-H2-E, except that the reactor vessel does not fail (core damage is arrested in vessel due to successful ex-vessel cooling). The source term for this category is bounded by the L-H2-E case. The total baseline frequency for this release category is 3.39E-8/yr for Unit 1 and 4.03E-8/yr for Unit 2.

### F.2.4.11 Release Category GEH

This release category involves core damage sequences due to SGTR with failure of high pressure injection from the Refueling Water Storage Tank (RWST). This results in early core damage at high pressure, with containment bypass. As these sequences bypass containment and occur early (prior to successful implementation of protective action recommendations), the frequency of this release category is considered to be a component of the LERF (large early release frequency). The source term for this category is bounded by the SGTR case. The total baseline frequency for this release category is 1.63E-8/yr for Unit 1 and 9.87E-8/yr for Unit 2.

### F.2.4.12 Release Category GLH

This release category involves core damage sequences due to SGTR with successful high pressure injection from RWST, but failure of ruptured SG isolation, or SG overfill, followed by failure of alternative actions to cool down and depressurize the RCS results in late core damage at high reactor pressure, with containment bypass. Core damage is delayed for hours during this event due to the long time available prior to RWST depletion. The source term for this category is bounded by the SGTR case. The total baseline frequency for this release category is 1.78E-7/yr for Unit 1 and 1.03E-6/yr for Unit 2.

### F.2.4.13 Release Category L-SR-E

This release category involves core damage sequences due to Pressure- or Temperature-Induced SGTR. These sequences involve high RCS pressure with at least one dry, depressurized SG leads to failure of the SG tubes and assumed containment bypass. This may result in a short-duration release, terminated when the steam generator relief valves reseat. However, assuming that the relief valves do not reseat, the source term is similar to the SGTR release category GEH. The frequency of this release category is considered to be a component of the LERF. The total baseline frequency for this release category is 3.85E-8/yr for Unit 1 and 4.34E-8/yr for Unit 2.

### F.2.4.14 Release Category ISLOCA

This release category involves core damage sequences due to interfacing system LOCA (ISLOCA). ISLOCA results in loss of RCS inventory and failure of ECCS systems for makeup and/or recirculation, and ultimately core damage (assumed to be at high pressure) with containment bypass. Core damage and vessel failure are assumed to occur within one hour. Although the release is into the Auxiliary Building it is assumed to be essentially unscrubbed. The frequency of this release category is considered to be a component of the LERF. The total baseline frequency for this release category is 3.22E-8/yr for both Unit 1 and Unit 2.

# F.3 LEVEL 3 PRA ANALYSIS

This section addresses the critical input parameters and analysis of the Level 3 portion of the probabilistic risk assessment. In addition, Section F.7.3 summarizes a series of sensitivity evaluations to potentially critical parameters.

## F.3.1 Analysis

The MACCS2 code (NRC 1998) is used to perform the Level 3 PRA for the Prairie Island Nuclear Generating Plant. PINGP site specific parameters are used for population distribution and economic parameters using the NRC endorsed SECPOP2000 code (NRC 2003). Plant-specific release data included the time-dependent distribution of nuclide releases and release frequencies. The behavior of the population during a release (evacuation parameters) is based on plant decisions and when certain site-specific setpoints are reached. Other input parameters given with “Sample Problem A” from the MACCS2 manual formed the basis for the present analysis. These data are used in combination with site-specific meteorology to simulate the probability distribution of impact risks (both exposures and economic effects) to the surrounding 50-mile radius population as a result of the release accident sequences at PINGP.

Note regarding errors with the SECPOP2000 code: During performance of the PINGP analysis, three SECPOP2000 code errors were publicized, specifically: 1) incorrect column formatting of the output file, 2) incorrect 1997 economic database file end character resulting in the selection of data from wrong counties, and 3) gaps in the 1997 economic database numbering scheme resulting in the selection of data from wrong counties. All three errors have been addressed in the PINGP analysis (via industry-developed formatting fixes) such that selection of proper counties by SECPOP2000 has been confirmed and the MAACS2 outputs used to quantify MMACR have been verified to be correct.

## F.3.2 Population

The population surrounding the PINGP site is estimated for the year 2034.

Population projections within 50 miles of PINGP are determined using SECPOP2000, (NRC 2003) utilizing a geographic information system (GIS). U.S Census block-group level population data is allocated to each sector based on the area fraction of the census block-groups in that sector. U.S. Census data from 1990 and 2000 are used to determine a ten year population growth factor for each of the 50-mile radius rings. The population growth factor for each ring is applied uniformly to all sectors in the ring to calculate the year 2034 population distribution.

Population distributions are given at distances to 1, 2, 3, 4, 5, 10, 20, 30, 40 and 50 miles from the plant and in the direction of each of the 16 compass points (i.e., N, NNE, NE……NNW).

The total year 2034 population estimate for the 160 sectors (10 distances × 16 directions) in the region is provided in Table F.3-2. The ten year population growth factor (in parenthesis) and distribution of the population is given for the 10-mile radius from PINGP and for the 50-mile radius from PINGP in Tables F.3-1 and F.3-2, respectively.

### F.3.3 Economy

MACCS2 requires certain 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 sectors. These values are calculated using the SECPOP2000 code (NRC 2003). SECPOP2000 utilizes economic data from the U.S. Department of Agriculture, “1997 Census of Agriculture” (USDA 1998) and from other 1998 and 1999 data sources. Economic values for up to 97 economic zones are calculated and allocated to each of the 160 sectors.

In addition, generic economic data that are applied to the region as a whole are revised from the MACCS2 sample problem input when better information is available. These revised parameters include per diem living expenses (applied to owners of interdicted properties and relocated populations), relocation costs (for owners of interdicted properties), and value of farm and non-farm wealth. These values are updated to the year 2006 value using the Consumer Price Index ratio.

PINGP MACCS2 economic parameters are listed on next page:

**PINGP MACCS2 Economic Parameters**

| Variable | Description | PINGP Value |
|---|---|---|
| DPRATE[1] | Property depreciation rate (per yr) | 0.2 |
| DSRATE[1] | Investment rate of return (per yr) | 0.12 |
| EVACST[2] | Daily cost for a person who has been evacuated ($/person-day) | 48.72 |
| POPCST[2] | Population relocation cost ($/person) | 9022.00 |
| RELCST[2] | Daily cost for a person who is relocated ($/person-day) | 48.72 |
| CDFRM0[2] | Cost of farm decontamination for various levels of decontamination ($/hectare) | 1015.00[4]<br>2256.00[4] |
| CDNFRM[2] | Cost of non-farm decontamination per resident person for various levels of decontamination ($/person) | 5413.00[4]<br>14435.00[4] |
| DLBCST[2] | Average cost of decontamination labor ($/man-year) | 63155.00 |
| VALWF0[3] | Value of farm wealth ($/hectare) | 2469.00 |
| VALWNF[3] | Value of non-farm wealth ($/person) | 130602.00 |

(1) DPRATE and DSRATE are based on NUREG/CR-4551 value (NRC 1990).
(2) These parameters for PINGP use the NUREG/CR-4551 value (NRC 1990), updated to the 2006 CPI value.
(3) VALWF0 and VALWNF are based on SECPOP2000 values for PINGP, updated to the 2006 CPI value.
(4) A value is provided for each level of the two levels of decontamination modeled. Two levels of decontamination is consistent with Sample Problem A.

### F.3.4 Food and Agriculture

Food ingestion is modeled using the new MACCS2 ingestion pathway model COMIDA2 (NRC 1998a), consistent with Sample Problem A. 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. The fraction of population dose due to food ingestion is typically small compared to other population dose sources. For PINGP, approximately less than one percent of the total population dose is due to food ingestion.

### F.3.5 Nuclide Release

MACCS2 requires input for 60 radionuclide. The core inventory at the time of the accident is based on a plant specific calculation and results provided in the PINGP USAR. PINGP USAR Appendix D, Rev. 18 Table D.1-1 provides the core inventory for 20 significant nuclides that correspond to MACCS2. The core inventory corresponds to end-of-cycle values (core average exposure of 50,000 MWD/MTU) for the PINGP core. Additional core inventory for the remaining 40 nuclides is obtained from MACCS2 Sample Problem A (NRC 1998a). The values for these 40 nuclides are adjusted to account for the PINGP power level (as compared to the Sample Problem A core power level). In addition, these values are increased by a factor of 1.39, which is the average increase of the PINGP 20 nuclides compared to those provided in Sample Problem A. Table F.3-3 provides a comparison of the MACCS2 PINGP core inventory and the Sample Problem A core inventory (as adjusted to account for the PINGP power level).

PINGP nuclide release categories are related to the MACCS categories as shown in Table F.3-4. All releases are modeled as occurring at a height of 62 meters (204'-4½") above grade elevation, which coincides with the top of the Containment Building (NMC 2007). The thermal content of each of the releases are assumed to be 1.0E+07 watts based on values provided in Sample Problem A and NUREG/CR-4551 (NRC 1990).

Two nuclide release sensitivity cases were performed to determine the effect of release height and thermal content assumptions. One sensitivity case modeled the releases occurring at ground level (0.0 meters). The second sensitivity case modeled the thermal content of each release to be the same as ambient (i.e., buoyant plume rise is not modeled). The results are discussed in Section F.7.3.4.

A final aspect to consider is the magnitude and timing of the radionuclide releases. Multiple release duration periods were defined which represented the time distribution of each category's releases. Release inventories of each of the multiple chemical forms of the cesium (Cs) and tellurium (Te) releases were available from the MAAP code output. Representative MAAP cases for each of the release categories were chosen based on a review of the Level 2 model cutsets and the dominant types of scenarios that contributed to the results. A brief description of each of those MAAP cases is provided in Table F.3-5, and a summary of the release magnitude and timing for those cases is provided in Table F.3-6.

### F.3.6 Evacuation

A reactor scram (automatic shutdown) signal begins each evaluated accident sequence. A General Emergency is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public. Therefore, the timing of the General Emergency declaration is sequence specific and ranges from 42 minutes to 24.1 hours for the release sequences evaluated.

The MACCS2 User's Guide input parameters of 95 percent of the population within 10 miles of the plant [Emergency Planning Zone (EPZ)] evacuating and 5 percent not evacuating are employed. These values have been used in similar studies (e.g., Hatch (SNOC 2000) and Calvert Cliffs (BGE 1998)) and are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the EPZ. The evacuees are assumed to begin evacuating 90 minutes after a General Emergency has been declared and are evacuated at an average radial speed of 3.35

miles per hour (1.5 m/sec). This speed is the time weighted value accounting for season, day of the week, time of day, weather conditions, and special events. The evacuation time weighted average of 268 minutes is for the full 0-10 mile EPZ, an assumed 15 minute notification time, 15 minutes for evacuation preparation, and 60 minutes average departure time. (TCDS 2003)

One evacuation sensitivity case was performed to determine the impact of evacuation assumptions. The sensitivity case reduced the evacuation speed by a factor of two (to 0.75 m/sec), resulting in a total evacuation time that exceeded the longest evacuation time used for the PINGP evacuation analysis. The results are discussed in Section F.7.3.3.

### F.3.7 Meteorology

Annual PINGP meteorology data from year 2003 is used in MACCS2 for the base case results. The year 2003 meteorological data set is utilized for the PINGP base case MACCS2 analysis based on the fact that the year 2003 provided the most complete data set, the highest population dose risk and offsite economic cost risk, and is judged to be the most conservative.

Year 2003, 2004, and 2005 meteorology data for the PINGP site contains 10, 22, and 60 meter wind speed, wind direction, and temperature tower data as well as site specific precipitation data. The 2003 PINGP meteorological data set contained 33 total hours of missing data, representing 0.38% of the hourly readings. The 2004 and 2005 PINGP meteorological data sets contained 70 and 65 total hours of missing data, respectively, representing 0.80% and 0.74% of the hourly readings. Therefore, the year 2003 provided the most complete data set.

The year 2003 meteorological data set contained eight gaps of missing data (33 hours, 0.38%). Traditionally, up to 10% of missing data is considered acceptable. Of the missing gaps, five gaps consisted of less than 6 hours and interpolation was used to fill in the missing meteorological data. Three gaps consisted of six hours or more of missing data (6 hr., 6 hr., and 7 hr. gaps). Missing meteorological data gaps of more than 6 hours were filled based on substituting data from the same time of day from the day just before or after the missing data in order to account for seasonal variations and the onset of severe weather. It is noted that MACCS results used in the SAMA analysis are the statistical mean of 349 weather sequences (each sequence contains 120 hours of data) chosen at random from pre-sorted weather bins. Due to the large number of samples analyzed, the adjustment of any particular weather sequence has negligible impact on the mean results.

PINGP MACCS2 analysis evaluated three representative meteorological data sets (Calendar years 2003, 2004, and 2005). The use of the most conservative data set (year 2003) accounts for any weather sequences. Based on the multiple years analyzed, minimum data gaps in the year 2003 meteorological data, and the sampling methodology used, the reported mean results are judged acceptable and appropriate for use in averted cost risk calculations.

Meteorological data is prepared for MACCS2 input as follows:

1. Wind speed and direction from the 10-meter sensor of the site tower were combined with precipitation (hourly cumulative). If the lower wind speed or direction is unavailable, mid and/or upper directions are used to estimate the wind speed or direction. Onsite precipitation from PINGP is utilized. Missing or suspect precipitation data is supplemented with data from the Minneapolis – St. Paul International Airport.
2. If a brief period (i.e., < 6 hr.) of missing data exists for all tower sensors, interpolation is used between hours.
3. For larger data voids (i.e., > 6 hr.), tower data from the previous or following day is utilized to fill data gaps (for the same time of day).
4. Atmospheric stability is calculated according to the vertical temperature gradient of the tower temperature data.
5. Atmospheric mixing heights are specified for morning and afternoon. These values were taken from the document *Mixing Heights, Windspeeds, and Potential for Urban Air Pollution throughout the Contiguous United States* (EPA 1972).

   This source defined morning as being the four-hour period from 0200 to 0600 Local Standard Time and afternoon as being the four-hour period from 1200 to 1600 Local Standard Time.

   The Code Manual for MACCS2: Volume 1 (from Appendix A, pages A-1 and A-2) states the following:

   > “The first of these two values corresponds to the morning mixing height and the second to the afternoon height. In the current implementation, the larger of these two values and the value of the boundary weather mixing height is used by the code.”
   >
   > “In its present form, that atmospheric model implemented in MACCS2 does not allow a change in the mixing layer to occur during transport of the plume. Mixing layer height is assumed to be constant and therefore only a single value is used by the code.”

For the PINGP MACCS2 analyses, these conditions mean that, only the afternoon mixing height is used since it is larger than the morning mixing height. Note that the boundary weather mixing height, wind speed and stability category are only used when there is no meteorological data. These fixed boundary weather values are ignored by the code when an hourly meteorological data file is supplied by the user, as was the case in the MACCS2 runs for PINGP.

As noted above, site meteorological data for years 2004 and 2005 are also evaluated as sensitivity cases to ensure year 2003 data is an appropriate data set. The results are discussed in Section F.7.3.1.

### F.3.8 MACCS2 Results

Table F.3-7 shows the mean off-site doses and economic impacts to the region within 50 miles of PINGP for each of ten release categories calculated using MACCS2. Mean off-site dose impacts are multiplied by the annual frequency for each release category and then summed to obtain the dose-risk and offsite economic cost-risk (OECR) for each unit. Table F.3-7 provides the Unit 1 and Unit 2 results, respectively.

## F.4 BASELINE RISK MONETIZATION

This section explains how NMC calculated the monetized value of the status quo (i.e., accident consequences without SAMA implementation). NMC also used this analysis to establish the maximum benefit that could be achieved if all on-line PINGP risk were eliminated, which is referred to as the Maximum Averted Cost-Risk (MACR).

The calculations below have been performed using Unit 1 input. The same process used for the Unit 1 case is also used to establish the MACR for Unit 2.

Section F.4.6 summarizes the results for these cases.

### F.4.1 Off-Site Exposure Cost

The baseline annual off-site exposure risk was converted to dollars using the NRC's conversion factor of $2,000 per person-rem, and discounted to present value using NRC standard formula (NRC 1997):

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

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 (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 2.94 person-rem. 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 for Unit 1 is $88,132 per person.

### F.4.2 Off-Site Economic Cost Risk

The Level 3 analysis showed an annual off-site economic risk of $15,852 for Unit 1. Calculated values for off-site economic costs caused by severe accidents must be discounted to present value as well. This is performed in the same manner as for public health risks and uses the same C value. The resulting value is $238,408.

### 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:

$$W_{IO} = R\{(FD_{IO})_S - (FD_{IO})_A\}\{[1 - \exp(-rt_f)]/r\}$$

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) (9.79E-06 (total CDF))

$D_{IO}$ = 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 $F_A$ is zero, the best estimate of the immediate dose cost is:

$$W_{IO} = R\,(FD_{IO})_S\{[1 - \exp(-rt_f)]/r\}$$

$$= 2{,}000 * 9.79\text{E-}06 * 3{,}300 * \{[1 - \exp(-0.03 * 20)]/0.03\}$$

$= \quad \$972$

For long-term dose, the NRC recommends using the following equation:

Equation 2:

$$W_{LTO} = R\{(FD_{LTO})_S - (FD_{LTO})_A\} \{[1 - \exp(-rt_f)]/r\}\{[1 - \exp(-rm)]/rm\}$$

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 $F_A$ is zero, the best estimate of the long-term dose is:

$$W_{LTO} = R\,(FD_{LTO})_S \{[1 - \exp(-rt_f)]/r\} \{[1 - \exp(-rm)]/rm\}$$

$$= 2{,}000 * 9.79E\text{-}06 * 20{,}000 * \{[1 - \exp(-0.03 * 20)]/0.03\} \{[1 - \exp(-0.03 * 10)]/0.03 * 10\}$$

$$= \$5{,}090$$

The total occupational exposure is then calculated by combining Equations 1 and 2 above. The total accident related on-site (occupational) exposure risk ($W_O$) for Unit 1 is:

$$W_O = W_{IO} + W_{LTO} = (\$972 + \$5{,}090) = \$6{,}062 \text{ person-rem}$$

### 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:

$$PV_{CD} = [C_{CD}/mr][1-\exp(-rm)]$$

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 total CDF (9.79E-06) to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent for Unit 1 is \$191,000.

### F.4.5 Replacement Power Cost

Long-term replacement power costs were determined following the NRC methodology in 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 PINGP's size relative to the "generic" reactor described in NUREG/BR-0184 (NRC 1997) (i.e., 560 megawatt electric/910 megawatt electric), the replacement power costs are determined to be 3.40E+09 ($-year). Multiplying 3.40E+09 ($-year) by the CDF (9.79E-06) results in a replacement power cost of $33,300 for Unit 1.

### F.4.6 Total Cost-Risk

The calculations presented in Sections F.4-1 through F.4-5 provide the on-line, internal events based MACR for a single unit. Given that the PINGP SAMA analysis is performed on a site basis and must consider the external events contributions, further steps are required to obtain a site based maximum averted cost-risk estimate that accounts for external events. This estimate, which is referred to as the Modified Maximum Averted Cost-Risk (MMACR) is calculated according to the following steps:

1. For presentation purposes, round each unit's MACR to the next highest thousand,
2. Multiply each unit's rounded MACR from the previous step by a factor of 2 to account for External Events contributions (refer to Section F.5.1.8 for additional details related to the basis for this factor),
3. Add the Unit 1 and Unit 2 results from step 2 together to obtain the MMACR.

The table on the next page summarizes the results of this process.

**PINGP MMACR DEVELOPMENT SUMMARY**

| Input | Unit 1 | Unit 2 |
|---|---|---|
| CDF (per year) | 9.79E-06 | 1.21E-05 |
| Dose-Risk (person-REM, single year) | 2.94 | 8.43 |
| OECR ($/yr) | 15,900 | 63,300 |
| Plant Net MWe | 560 | 560 |
| **Output** | | |
| Offsite Exposure Cost-Risk | $88,100 | $254,000 |
| Offsite Economic Cost-Risk | $238,000 | $953,000 |
| Onsite Exposure Cost-Risk | $6,062 | $7,461 |
| Onsite Cleanup Cost-Risk | $191,000 | $235,000 |
| Replacement Power Cost-Risk | $33,300 | $41,000 |
| Total Unit MACR (Rounded to Next Highest Thousand) | $557,000 | $1,490,000 |
| Unit MMACR (Includes External Events (MACR x 2)) | $1,114,000 | $2,980,000 |
| Site MMACR | $4,094,000 | |

## F.5 PHASE I SAMA ANALYSIS

The Phase I 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. The following subsections provide additional details of the Phase I process.

### F.5.1 SAMA Identification

The initial list of SAMA candidates for PINGP was developed from a combination of resources. These include the following:

- PINGP PRA results and PRA Group Insights
- Industry Phase II SAMAs (review of the potentially cost effective Phase II SAMAs for selected plants)
- Prairie Island Nuclear Generating Plant Individual Plant Examination IPE (PINGP IPE) (NSP 1994)
- PINGP IPEEE (NSP 1998)

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 PINGP.

In addition to the "Industry Phase II SAMA" review identified above, an industry based SAMA list was used in a different way to aid in the development of the PINGP specific SAMA list. While the industry SAMA review cited above was used to identify SAMAs that might have been overlooked in the development of the PINGP SAMA list due to PRA modeling issues, a generic SAMA list was used as an idea source to identify the types of changes that could be used to address the areas of concern identified through the PINGP importance list review. For example, if Instrument Air availability were determined to be an important issue for PINGP, the industry list would be reviewed to determine if a plant enhancement had already been conceived that would address PINGP's needs. If an appropriate SAMA was found to exist, it would be used in the PINGP list to address the Instrument Air 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 several industry SAMA analyses and has been provided in Addendum 1 for reference purposes.

### F.5.1.1 Level 1 PINGP Importance List Review

The PINGP PRA was used to generate a list of events sorted according to their risk reduction worth (RRW) values. The top events in this list are those events that would provide the greatest reduction in the PINGP CDF if the failure probability were set to zero. The events were reviewed down to the 1.02 level, which corresponds to about a 2 percent reduction in the CDF given 100 percent reliability of the event. If the dose-risk and offsite economic cost-risk were also assumed to be reduced by a factor of 1.02, the corresponding averted cost-risk would be about $22,000, which also accounts for the impact of External Events after applying a factor of 2. Similarly, the Unit 2 result was determined to be about $58,000. Both of these estimates are on the order of the dollar amount that would be expected to process a procedural change, i.e., no hardware modification. The lower end of implementation costs for SAMAs are expected to apply to procedural changes, which have previously been estimated to cost about $50,000 (CPL 2004). Given that the PINGP importance list was reviewed down to a level corresponding to an averted cost-risk of about $22,000 for Unit 1 and $58,000 for Unit 2, all events that are likely to yield cost beneficial improvements were addressed by this review process.

Tables F.5-1a and F.5-1b document the disposition of each event in the Level 1 PINGP RRW list for both Units 1 and 2, respectively. Note that no basic events were preemptively screened from the process even if they solely represent sequence flags. Whatever the event, the intent of the process is to determine if insights can be gleaned to reduce the risk of the accident evolutions represented by the events listed. However, unique SAMAs are not identified for all of the events in the RRW list. Previously identified SAMAs are suggested as mitigating enhancements when those SAMAs (or similarly related changes) would reduce the RRW importance of the identified event. It is recognized that in some cases, additional requirements may need to be imposed on the SAMA to get a reduction in the RRW value for the basic event listed. In these cases, if an existing SAMA can approximate such an impact, then it is considered to address the relevant event and provide a first order indication of the potential benefit. If warranted, a more detailed PRA analysis may then be required to provide a better estimate of the actual potential cost-benefit.

### F.5.1.2 Level 2 PINGP Importance List Review

A similar review was performed on the importance listings from the Level 2 results that involved contributions to Large Early Release Frequencies (LERF). In this case, cutsets that contribute to LERF that exhibited a RRW $\geq$ 1.02 were reviewed for both Units 1 and 2 to identify any potential SAMA improvements.

The Level 2 RRW values were reviewed down to the 1.02 level. As described for the Level 1 RRW list, events below the 1.02 threshold value are estimated to yield an averted cost-risk less than that required for a procedural modification (approximately $50,000) and were not considered to be likely candidates for identifying cost effective SAMAs. As such, the events with RRW values below 1.02 were not reviewed. Tables F.5-2a and F.5-2b document the disposition of each event in the LERF PINGP RRW list for both Units 1 and 2. The same ground rules related to event disposition in the Level 1 importance tables were utilized in the Level 2 importance tables.

### F.5.1.3 PINGP PRA Group Insights

A review of the current PRA model results and insights was conducted in order to identify any additional risk reduction opportunities that could be examined as potential SAMA improvements. This review did not include potential PRA modeling enhancements (as these changes only result in enhancements to the ability to measure plant risk), but rather plant changes that reduce risk (through hardware modifications, procedural enhancements, operator training improvements, etc.). The review indicated that the large majority of risk reduction opportunities available through implementation of individual plant changes are encompassed by the previously identified listing of SAMA improvements (most of these were identified from the importance list reviews for CDF and LERF based on the current PRA model of record, as described in Sections 5.1.1 and 5.1.2 above). There were no additional SAMA improvements identified by this review.

### F.5.1.4 Industry SAMA Analysis Review

The SAMA identification process for PINGP is primarily based on the PRA importance listings/insights, the IPE, and the IPEEE. In addition to these plant specific sources, selected industry SAMA analyses were reviewed to identify any Phase II SAMAs that were determined to be potentially cost beneficial at other plants. These SAMAs were further analyzed and included in the PINGP SAMA list only if they were considered to be potentially cost beneficial for PINGP. The following subsections provide a more detailed description of the identification process.

While many of these SAMAs are ultimately shown not to be cost beneficial, some are close contenders and a small number have been shown to be cost beneficial at other plants. Use of the PINGP importance ranking should identify the types of changes that would most likely be cost beneficial for PINGP, but review of selected industry Phase II SAMAs may capture potentially important changes not identified for PINGP due to PRA modeling differences. Given this potential, it was considered prudent to include a review of selected industry Phase II SAMAs in the PINGP SAMA identification process.

The Phase II SAMAs from the following U.S. nuclear sites have been reviewed:

- V.C. Summer (SCE&GC 2002)
- H.B. Robinson (CPL 2002)
- Palisades (NMC 2005b)
- Dresden (Exelon 2003a)
- Quad Cities (Exelon 2003b)
- Brunswick (CPL 2004)
- Monticello (NMC 2005a)
- Susquehanna (PPL 2006)
- Browns Ferry (NRC 2005c)
- Calvert Cliffs (NRC 1999)
- D.C. Cook (NRC 2005b)

Five PWR and six boiling water reactor (BWR) sites were chosen from available documentation to serve as the Phase II SAMA sources. Most of the Phase II SAMAs from these sources are not included in the PINGP SAMA list. The industry Phase II SAMAs that were considered to have the potential to be cost effective for PINGP were independently identified through the PINGP importance list reviews. The remaining industry Phase II SAMAs were judged not to provide any significant benefit or added insight to the plant, or were addressed by SAMAs more suitable to PINGP's needs. These SAMAs were not considered further and no SAMAs unique to the review of the industry Phase II SAMAs were included in the PINGP SAMA list.

### F.5.1.5 PINGP IPE Plant Improvement Review

The PINGP IPE generated a list of risk-based insights and potential plant improvements. Typically, changes identified in the IPE process are implemented and closed out; however, there are some items that may not have been completed due to high projected costs or other criteria. Because the criteria for implementation of a SAMA may be different than what was used in the post-IPE decision-making process, these recommended improvements are re-examined in this analysis. The following table summarizes the status of the potential plant enhancements resulting from the IPE process and their treatment in the SAMA analysis:

| Item No. | Description of Potential Enhancement | Status of Implementation | Disposition |
|---|---|---|---|
| 1. | Procedure revision to utilize the cross-tie from station air to instrument air. The station air compressors are cooled from loop B cooling water and would not be affected by a LOOP A CL pipe break. If the cross-tie could be accomplished within 1 hour after the flood initiator, main feedwater or bleed and feed cooling could be restored and core melt could be prevented. | Procedural modifications have been implemented. | No further review required. |
| 2. | Revise procedure C35 AOP1, "Loss of Cooling Water Header A or B", to address the problem of closure of the turbine building cooling water header isolation valve and the subsequent loss of cooling water to the main feedwater lube oil coolers and condensate pump oil coolers. Analysis has shown that the main feedwater pumps can conservatively operate without cooling water for approximately 20 minutes before possible pump damage. | This recommendation was implemented through the disposition listed below for item #3. | No further review required. |
| 3. | To limit the impact of AFW pump room flooding due to Cooling Water System header rupture, provide a means to either allow additional water flow out of the room or to segregate the room into two compartments. | Calculation ENG-ME-148, Rev. 1, "Cooling Water Header Pipe Failure Causing Flooding in the Auxiliary Feedwater Pump/Instrument Air Compressor Room", addressed this recommendation. This position paper documents the qualifications, design features and periodic inspections in place that provide confidence that the probability of occurrence of the pipe rupture is negligible. In addition to pipe replacements and upgrades that were performed in 1992, it is likely that operators or other personnel who periodically transit these rooms would notice a substantial piping leak. | No further review required. |

| Item No. | Description of Potential Enhancement | Status of Implementation | Disposition |
|---|---|---|---|
| 4. | Emphasize in training the importance of bleed and feed and the operator actions that are necessary for success as bleed and feed is a significant contributor to the overall CDF. | Operator training, course outlines, and lesson plans have been revised to emphasize the importance of this and other IPE insights in the operation and maintenance of the plant. | No further review required. |
| 5. | Emphasize in training the importance of the crosstie between the motor driven AFW pumps and the operator actions that are necessary for success as the AFW crosstie is a significant contributor to the overall CDF. | See implementation status for #4 above. | No further review required. |
| 6. | Emphasize in training the importance of switchover to high and low head recirculation and the operator actions that are necessary for success as switchover to recirculation is a significant contributor to the overall CDF. | See implementation status for #4 above. | No further review required. |
| 7. | Emphasize in training the importance of RCS cooldown and depressurization to terminate safety injection before ruptured steam generator overfill and the operator actions that are necessary for success as this action is a significant contributor to the overall CDF. | See implementation status for #4 above. | No further review required. |
| 8. | Revise step 18 of FR-C.1, "Response to Inadequate Core Cooling", such that the operator checks for adequate steam generator level before attempting to start an RCP. If the RCPs are started with a "dry" steam generator with core exit thermocouples greater than 1200°F, hot gases could be pushed up into the steam generator tubes causing creep rupture of the tubes and a possible containment bypass if one of the steam generator relief valves were to lift. | Implemented. | No further review required. |
| 9. | The in-core instrument tube hatches for both units should be secured open during normal operation. This could be accomplished by using a solid bar or other device, instead of a chain, to keep the hatch open but still prevent inadvertent entry during normal operation. Having this hatch open greatly improves the probability of recovering from a core damage event in-vessel (without vessel rupture), by allowing injection water from the RWST to flow into the reactor cavity and to provide cooling to the lower vessel head. | The hatch was replaced with a metal cage to allow water to flow freely. | No further review required. |

### F.5.1.6 PINGP IPEEE Plant Improvement Review

The PINGP IPEEE also generated a list of risk-based insights and potential plant improvements. Typically, changes identified in the IPEEE process are implemented and closed out; however, there are some items that may not have been completed due to high projected costs or other criteria. Because the criteria for implementation of a SAMA may be different than what was used in the post-IPEEE decision-making process, these recommended improvements are re-examined in this analysis. The following table summarizes the status of the potential plant enhancements resulting from the IPEEE process and their treatment in the SAMA analysis:

| Item No. | Description of Potential Enhancement | Status of Implementation | Disposition |
|---|---|---|---|
| 1. | Add fire wrap or other fire barrier material to the exposed length of cable 1DCB-1 (control power to Bus 16) above cable tray 1SG-LB22 in FA 32 (Unit 1 side AFW pump/instrument air compressor room). In the fire PRA, the critical component for this fire is the 12 AFW pump. Although this pump resides in FA 31, loss of control power to Bus 16 will result in loss of the automatic start of the pump. | Implemented. | No further review required. |
| 2. | Add instructions to Fire Safety Procedure F5, Appendix D, for the operator to locally start an available roof exhaust fan to reestablish safeguards screenhouse ventilation. In many fire core damage sequences (fire may be initiated in a number of fire areas), the 121 cooling water pump and a roof exhaust fan are available, but since (in these sequences) the fan and pump are powered from the opposite train, the fan is not running. This leads to failure of the 121 CL pump due to lack of sufficient ventilation. | Subsequent review revealed that procedures already exist to accomplish this task for fires that cause loss of power from MCC 1AB1 or 1AB2. For this operator action, the fire areas of concern are FA 80 (480V Safeguards Swgr Room (Bus 111)), FA 81 (4kV Safeguards Swgr Room (Bus 15)), and FA 22 (480V Safeguards Swgr Room (Bus 121)). | No further review required. |

| Item No. | Description of Potential Enhancement | Status of Implementation | Disposition |
|---|---|---|---|
| 3. | Add instructions to Fire Safety Procedure F5 App. D for the operator to manually open a suction supply valve to the 12 AF pump on a fire in FA 32 (Unit 1 side AFW pump/IA compressor room). On an air compressor large oil spill fire, the assumption is that the fire causes spurious closure of MV-32335 prior to loss of power from MCC 1A2. The cooling water supply valve MV-32027 could also be opened. An alternative would be to wrap the length of conduit for cable 1A2-6A that traverses FA 32. | Upon further review of the procedure, it was found that direction is included in F5 App. D for the operator to de-energize MCC 1A2 and manually operate as necessary the suction valves for 12 MDAFWP for a fire in FA 32. However, no credit was given to this operator action since it was postulated that the 12 MDAFWP discharge valves (MV-32381 and MV-32382) could spuriously close through a hot short on cable 1CB-52, which would have the same impact as the hot short on cable 1A2-6A for MV-32335. Therefore, it was decided to conservatively not credit this operator action. | No further review required. |
| 4. | Ensure that existing training for manual fire suppression in the mitigation of fires in the control room and relay room (fire brigade to relay room) includes a discussion of the risk significance of this action in the prevention of core damage. If successful, this action prevents the need for shutdown outside the main control room. | Revisions were made to lesson plans to include this recommendation. | No further review required. |
| 5. | Ensure that existing training for the operator task to shutdown the plant from outside the control room per F5 App. B includes a discussion of the risk significance of this action in the prevention of a core damage accident. | Revisions were made to lesson plans to include this recommendation. | No further review required. |
| 6. | Ensure that existing training for the operator task to perform bleed and feed cooling of the RCS includes a discussion of the risk significance of this action in the prevention of a core damage event due to internal fires. | Revisions were made to lesson plans to include this recommendation. | No further review required. |
| 7. | Ensure that training (lesson plans, outplant checkoffs, etc. as appropriate) exists for the operator task to perform DC panel switching in the battery room and relay room for a fire in FA 59. Training should include information relative to the importance of this action to stopping loss of inventory through the RCS vent solenoid valves. | Revisions were made to lesson plans to include this recommendation. | No further review required. |

| Item No. | Description of Potential Enhancement | Status of Implementation | Disposition |
|---|---|---|---|
| 8. | Verify cable separation in the G-panel due to potential for a large fire internal to the panel to cause the loss of offsite and onsite power. Power would then have to be restored from the diesel generators from outside the control room. This recommendation is made only to provide added assurance of this critical assumption with respect to its impact on plant risk due to fires. | A visual inspection was performed on the G panel and confirmation was made on the proper design separation between trains. Additionally, proper separation of cables throughout the plant was verified. | No further review required. |
| 9. | Upgrade the anchorage for the main Cardox tank for Relay Room automatic fire suppression. From walkdown activities, it was found that a potentially weak anchorage exists for the main CO2 storage tank in the Unit 1 Turbine Building. Suppression in the Relay Room is important due to the critical equipment in this room required for safe shutdown of the plant. | The installation of new anchors for the Cardox Tank was completed and documented under the plant design change process. | No further review required. |
| 10. | Upgrade the anchorage for the diesel driven fire water pump batteries and its fuel oil day tank. From walkdown activities, it was found that a potentially weak anchorage exists for the diesel driven fire water pump batteries and fuel oil day tank in the plant Screenhouse. This is a concern in that seismic events of sufficient magnitude to cause a loss of offsite power could also render the diesel fire pump unavailable. | The installation of new anchors for the diesel driven fire water pump batteries and its fuel oil day tank was completed and documented under the plant design change process. | No further review required. |

### F.5.1.7 Use of External Events in the PINGP SAMA Analysis

The external events examination was conducted in three distinct phases: seismic, internal fires, and other external events. The following summarizes the conclusions of these assessments, including specific insights and recommendations. As a result of reviewing these historical analyses and their results, no additional SAMAs were identified that required further consideration for the Phase I analysis.

#### F.5.1.7.1 Seismic Analysis

Northern States Power (NSP) had originally planned to respond to Generic Letter 88-20, Supplement 4, by performing a seismic probabilistic risk assessment (PRA) for PINGP. By letter dated September 25, 1995, PINGP notified the NRC staff of a change in the manner in which the seismic IPEEE would be completed. This change was based on new information regarding large reductions in the seismic hazard estimates for sites in the eastern United States, as presented in NUREG-1488 (NRC 1993). This information was incorporated within Supplement 5 of Generic Letter 88-20, which provides the basis for NSP's decision to change the approach of completing the seismic IPEEE from a seismic PRA to a seismic margins assessment.

A portion of the effort for the PRA was accomplished (i.e., walkdowns and initial screening) when the NRC issued Supplement 5 to the Generic Letter. NSP elected to change its approach in accordance with Supplement 5 and completed the analysis of seismic events in the form of a reduced scope seismic margins assessment with the focus on a few known weaker, but critical, components. The majority of the components included in the assessment were determined to meet the screening criteria established in EPRI NP-6041-SL (EPRI 1991). This result in itself indicates that most of the components have a relatively high seismic capacity. The remaining components; i.e., those not meeting the screening criteria, were evaluated further and were determined to be: 1) adequate for the safe shutdown earthquake (SSE); 2) unnecessary due to the particular seismic failure mode and/or available plant equipment redundancy; or 3) were to be addressed under the closure of the PINGP SQUG program. Overall, it was concluded that there was no significant plant vulnerability to severe accidents attributable to seismic events at PINGP.

It should be noted that the seismic analysis conducted as part of the IPEEE program was done in conjunction with the efforts at PINGP to address seismic issues associated with the USI A-46 program (NRC 1987). Further, it was shown that many unscreened components that were not dispositioned in the USI A-46 program would not be expected to lead to the inability to cool the core if they were assumed to fail following a seismic event. In each case, additional random failures of equipment are necessary before inadequate core cooling would be expected.

Other significant conclusions of the seismic margins assessment include:

- The seismic walkdowns performed as part of the IPEEE found most of the components and structures reviewed to be seismically adequate (i.e., suitably anchored and/or seismically rugged). Those items that could be considered potentially vulnerable were subjected to the more rigorous seismic evaluation referred to above.
- Concrete block walls were either screened from further consideration because their failure would cause no adverse consequences, or they were further evaluated and found to have sufficient seismic capacity.
- The review of relays credited in the IPE revealed that there were relays beyond those considered in the SQUG program scope that had to be evaluated. However, it was determined that none of these relays were considered "bad actors".

- Few flat bottom tanks fell solely under the scope of the seismic IPEEE (i.e., SQUG had identified some tanks as outliers that were addressed under the closure of that program). Those that did were either screened or shown to have limited consequences should they fail.
- A review of containment response revealed no conditions unique to seismic events or that were not already evaluated as part of the internal events PRA (IPE).
- A recommendation from the seismic margins assessment was to restrain or remove wall hung ladders and scaffolding that were located near safety related equipment to reduce the impact of seismically induced relay chatter.

F.5.1.7.2 <u>Internal Fires Analysis</u>

The overall methodology used in the development of the PINGP Fire IPEEE conformed to the guidance provided by GL 88-20, Supplement 4 and detailed guidance provided by NUREG-1407 (NRC 1991), and has made use of past PRA experience, generic databases, and other defensible simplifications to the maximum extent possible. This methodology was summarized in the PINGP IPEEE submittal of September 1998. The PINGP fire study used an approach that combined the deterministic evaluation techniques from the Fire Induced Vulnerability Evaluation (FIVE) methodology with classical PRA techniques. The FIVE methodology provided a means of establishing fire boundaries as well as methods to evaluate the probability and the timing of damage to components located in a compartment involved in a fire. PRA techniques allow determination of compartment-specific core damage frequencies associated with fires within the various fire areas of the plant. For the PINGP Fire IPEEE, compartments were identified and evaluated, then quantified using the fault trees and event trees from the updated internal events PRA. The internal initiating events were evaluated to determine if they could also result from a fire. The relevant fire-induced initiating events and related fault trees were used to perform the quantification.

The core damage frequency resulting from fires was estimated to be less than 5E-5/yr. This total is on the same order of magnitude as the core damage frequency of the internal events PRA (Level 1, Rev. 1 – see Section F.2.1.2.1 above). It should be noted that these results included a number of conservative assumptions. For example, automatic and manual fire suppression techniques were not credited except in the control room, relay and cable spreading room, and the AFW pump rooms. Also, in most cases, fires were also assumed to completely engulf an area once ignited. In a few critical fire areas (FA), fire modeling was performed to more accurately predict the spread of credible fires occurring in those areas, and the scope of equipment affected by those fires. The areas that received fire modeling were the control room (FA 13), cable spreading and relay room (FA 18), both of the Auxiliary Feedwater/Instrument Air compressor rooms (FAs 31 and 32), the screenhouse basement (FA 41B), and the Unit 1 side Auxiliary Building 695' elevation (FA 58).

More than 89 percent of the plant risk associated with the internal fires can be traced to eight fire areas. These areas are the main control room (FA 13), Unit 1 side Auxiliary Feedwater/Instrument Air compressor room (FA 32), 480V safeguards switchgear room-Bus 111 (FA 80), 4160V safeguards switchgear room-Bus 16 (FA 20), Unit 1 Auxiliary Building elevation 715' (FA 59), Unit 2 Auxiliary Building elevation 695' (FA 73), the cable spreading and relay room (FA 18), and the Turbine Building ground and mezzanine floor (FA 69). Of these, the largest contributors to core damage frequency were fires originating in the main control room. Small fires in the panels that include the Main Feedwater system and Auxiliary Feedwater system controls that are successfully suppressed; along with large fires in the safeguards electrical panel (G-panel) dominated the risk from this fire area.

It should be noted that FA 73, Unit 2 Auxiliary Building elevation 695', did not receive detailed fire modeling, as did its Unit 1 counterpart fire area, FA 58. As a result, the core damage contribution from fires in FA 58 fell below the 1E-6/rx-yr reporting criteria, while the contribution from fires in FA 73 did not. If fire modeling had been applied to FA 73, it is expected that this fire area would have been shown to be even less significant to the Unit 1 Fire PRA results than FA 58.

Operator actions that dominated the fire PRA are associated with performing RCS bleed and feed operation, activation of the hot shutdown panel, local restoration of onsite power following station blackout from a control room G-panel fire, and manual fire suppression in the control room.

The principal finding of the IPEEE fire analysis is that there were no major vulnerabilities due to fire events at PINGP. Plant insights/improvements and their resolution were identified above in Section F.5.1.6, which also included two recommendations from the seismic/fire interactions review.

#### F.5.1.7.3 High Winds, Floods, and Others

The assessment of other external events in Appendix C of the IPEEE (NSP 1998) showed that there were no other credible external events besides fires and seismic activity that were a safety concern to the PINGP site. No vulnerabilities were identified, and the screening criteria contained in NUREG-1407 (NRC 1991) and Generic Letter 88-20 (Supplement 4) were satisfied for all events. Because there were no vulnerabilities found from this analysis, no changes to plant hardware or procedures were necessary.

#### F.5.1.7.4 Post-IPEEE External Hazards Review

In addition to the above summary of the PINGP IPEEE, an effort was made to review information since the conclusion of the original IPEEE in 1998 to determine if any outstanding issues exist that could warrant the implementation of any additional SAMAs with regard to external risk. Information for this review was obtained from inspection audits, RAIs, USAR changes, etc. Therefore, the following sources of information are outlined below with a summary of their review:

##### F.5.1.7.4.1 PINGP Response to RAIs from NRC regarding IPEEE Submittal (NSP 2000)

There were five major requests for additional information, with some containing multiple sub-topics of interest. Three of the requests can be categorized as related to seismic interactions, one related to non-seismic failures and human actions, and one related to seismic-induced fires. The responses from NMC involved detailed explanations and evaluations that satisfactorily address each of the questions, but none involving any structural or hardware modifications.

Since no outstanding items exist as a result of these RAIs, no new SAMAs are deemed necessary.

##### F.5.1.7.4.2 Response to Generic Letter 2003-01, "Control Room Habitability" (NMC 2003)

The purpose of this generic letter was to ensure that licensees are capable of meeting the applicable habitability regulatory requirements and the control room is designed, constructed, configured, operated, and maintained in accordance with the facility's design and licensing basis. One of the results found within this report is that inspections during the initial set of tests indicated that the seals for the doors that enter the control room envelope and the outside air isolation dampers could be a significant vulnerability. Thus, following initial testing, the seals on all the doors entering the control room envelope were replaced, and the outside air isolation dampers were replaced with bubble tight design dampers. Consistent with the current licensing bases, control room dose analyses were performed for the LOCA, the Main Steam Line Break (MSLB), and the Fuel Handling Accident (FHA). The LOCA dose analysis demonstrated that the dose to the Control Room operator satisfied General Design Criteria (GDC) 19 using 165 cfm unfiltered inleakage. The MSLB dose analysis demonstrated that the dose to the Control Room operator satisfied GDC-19 using 175 cfm unfiltered inleakage. An evaluation for the dose to the control room operator following a FHA demonstrated that the dose to the Control Room operator is less than the GDC-19 limits with unfiltered inleakage up to 700 cfm.

With regard to toxic chemicals, a probabilistic evaluation of chlorine and ammonia spills, determined that no automatic monitoring systems were required. Following NRC approval, the chlorine detection system was removed. PINGP used the guidance of Regulatory Guide 1.78 and 1.95 in determining the adequacy of operator protection in the event of a toxic chemical release. RG 1.95 recommended that a six hour air capacity for the SCBAs be readily available on site to ensure that sufficient time is available to transport additional bottled air from offsite locations. The regulatory guidance also stated that a minimum emergency crew should consist of those personnel required to maintain the plant in a safe condition, including orderly shutdown or scram (automatic shutdown) of the reactor. When a toxic gas event is detected, control personnel will place the Control Room ventilation in recirculation and don their SCBAs. PINGP can provide a minimum of six hours of air for 14 people: six Control Room operators, six out-plant operators and fire brigade, one chemist, and one shift manager. The breathing air supply consists of an auto-cascade air system with two Quick-Fill stations located on the missile shield wall outside the Control Room. The system also provides a redundant three hour supply of air in the event of an equipment failure on one of the stations. All SCBAs in the plant have Quick-Fill capability. Annually, Operations personnel must complete SCBA training and must don an SCBA and have it functional within 2 minutes for potential hazardous chemicals capable of entering the Control Room. With regard to reactor control capability in the event of smoke, it was concluded, using the guidance described in NEI 99-03, Rev. 1, Appendix A (NEI 2003), that a single smoke event originating from inside or outside the Control Room would not affect both the Control Room and the Hot Shutdown Panel areas. Plant Operators would be able to achieve and maintain safe shutdown (reactor control capability) from either the Control Room or the Hot Shutdown Panels if needed.

As a result, no areas of concern or outstanding vulnerabilities were identified regarding control room habitability; therefore, no additional SAMAs are warranted.

F.5.1.7.4.3 Prairie Island Nuclear Generating Plant, Units 1 and 2 NRC Tornado/Fire/Flood Integrated Inspection Report (NRC 2005a)

On June 30, 2005, the NRC completed an integrated inspection for Units 1 and 2. This inspection examined activities, selected procedures, records, observed activities, and personnel interviews. Based on the results of this inspection, the inspectors identified two external event-related findings. Both findings were determined to be of very low safety significance. As a result, no areas of concern or outstanding vulnerabilities were identified regarding this integrated inspection, and therefore, no additional SAMAs are warranted.

F.5.1.7.4.4 Prairie Island Nuclear Generating Plant, Units 1 and 2 NRC Triennial Fire Protection Baseline Inspection (NRC 2006)

Based on the results of this fire inspection, no significant outstanding vulnerabilities were identified that would warrant a specific SAMA to mitigate external risk. Two of the four findings identified during this inspection were determined to be of very low safety significance, and two are being addressed through the corrective action program and NFPA 805 implementation.

### F.5.1.8 Quantitative Strategy for External Events

The quantitative methods available to evaluate external events risk at PINGP are limited, as discussed above. In order to account for the external events contributions in the SAMA analysis, the assumption that the risk posed by external and internal events is approximately equal was imposed to simplify the calculation of averted cost-risk based on external events accidents.

Continuing on with the assumption that the internal and external events risks are assumed to be equal, the MACR calculated for the internal events model has been doubled to account for external events contributions. As identified in Section F.4.6, this total is referred to as the MMACR. The MMACR is used in the Phase I screening process to represent the maximum achievable benefit if all risk related to on-line power operations was eliminated. Therefore, those SAMAs with costs of implementation that are greater than the MMACR were eliminated from further review. The second stage of this strategy was to also apply the doubling factor to the Phase II analysis. Any averted cost-risk calculated for a SAMA was multiplied by two to account for the corresponding reduction in external events risk. The difference in the averted cost-risk estimates between the base case and the proposed SAMA were then compared with implementation costs to determine whether a particular SAMA was cost beneficial.

### F.5.2 Phase I Screening Process

The initial list of SAMA candidates is presented in Table F.5-3. The process used to develop the initial list is described in Section F.5.1.

The purpose of the Phase I 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 PINGP design, it is not retained.
- Engineering Judgment: Using extensive plant knowledge and sound engineering judgment, potential SAMAs are evaluated based on their expected maximum cost and dose benefits; those that are deemed not beneficial are screened from further analysis.

Table F.5-3 provides a description of how each SAMA was disposition in Phase I. Those SAMAs that required a more detailed cost-benefit analysis are evaluated in Section F.6.

Detailed cost-estimates were developed, using an outside vendor, for the most viable candidates. These cost estimates included cost estimates related to the four project phases: Study, Engineering and Design, Implementation and Life Cycle. A summary of cost estimates by phase breakdown is included in Table F.5-3 to help determine which SAMAs should be retained for further analysis in Phase II.

#### F.5.2.1 SAMA 6 (Install Equipment to Automatically Isolate Auxiliary Building Flooding):

This SAMA attempts to address the risk of Auxiliary Building flooding, which is dominated by floods in the lowest level (Zone 7, the 695' elevation, represented by initiating events I-AB7FLDA and I-AB7FLDB). The flooding is assumed to be due to a ruptured Cooling Water (CL) system pipe.

<u>Risk Benefit:</u>

For either unit, Auxiliary Building Zone 7 flooding initiating events account for only about 2% of the CDF and only about 1% of the LERF. Also, by definition, implementation of this SAMA will not provide any benefit in reducing the risk of SGTR-initiated events, which are an important component of the LERF.

<u>SAMA Implementation Cost:</u>

The cost and complexity of implementing this SAMA would be significant—involving system modifications that would entail extensive engineering support, specialized hardware and instrumentation, and regulatory analyses to support modifications to the facility. In order to minimize the cost of the modification, the existing ring header isolation MOVs would have to be used (those that currently split the ring header into two safeguards headers on an S-signal on either unit) in order to prevent a dual-unit outage to install new isolation valves. Under this design, however, isolation of an entire train of safeguards equipment (those supplied by CL) to stop the flooding event would leave both units susceptible to a single failure for important safety functions. Also, adding level instrumentation and automatic isolation logic in order to achieve the most risk benefit from this modification, additional logic to identify the affected CL header and trip the pumps supplying that header would have to be installed. If manual action to diagnose the situation and trip the right pumps is relied upon, a large portion of the risk benefit from this SAMA would not be realized. Also, at a minimum, one CC pump on each unit must be assumed to have failed as they are located in the CCHX room underneath each CL header.

Recommendation:

Screen this SAMA from further consideration.

### F.5.2.2 SAMA 6a (Segregate Flooding Zones):

This SAMA attempts to address the risk of Auxiliary Building flooding (see SAMA 6 discussion above), which is dominated by floods in the lowest level (Zone 7, the 695' elevation, represented by initiating events I-AB7FLDA and I-AB7FLDB). However, this SAMA addresses the problem by building curbs or other barriers to physically protect trains of potentially affected equipment from each other. Currently the SI pumps are not separated from each other with respect to flooding hazards. The RHR pits (containing the RHR pumps and heat exchangers) are separated but would both flood nearly simultaneously when water level reaches top of curb. Other equipment affected on the 695' elevation include MCCs supplying power to the ECCS MOVs, which are not separated and would fail simultaneously impacting both trains. It may be possible to increase height of curb around RHR pits to provide extended time to flooding, or to increase the curb height for the RHR pits.

Risk Benefit:

The maximum risk benefit for this SAMA is low (see SAMA 6 discussion above).

SAMA Implementation Cost:

The cost of implementing this SAMA is estimated to be significantly greater than that of SAMA 6. Furthermore, this SAMA relies on operator action to identify and isolate the header with the break (the current, pre-SAMA implementation situation). With the higher likelihood of isolation failure due to operator vs. automatic action, a large portion of the risk benefit from this SAMA would not be realized. Also, even with successful operator action, the result is the loss of at least one train of safeguards equipment.

Recommendation:

Screen this SAMA from further consideration.

### F.5.2.3 SAMA 8 (Install Additional Diesel Generator):

This SAMA addresses the risk of Station Blackout (SBO) events by installing an additional diesel generator that can be aligned should the onsite EDGs fail to provide power before offsite power can be restored. One option may be to provide an upgrade to the D3 and/or D4 non-safeguard diesel generators already onsite to provide a backup EDG supply.

Risk Benefit:

SBO is a significant contributor to CDF for both units (provides about 8% of the total CDF). However, it contributes <1% to the LERF, and approximately 1% to the frequency of all early containment failure sequences. All of the top SBO-related release categories involve sequences in which the containment and/or reactor vessel does not fail. The risk benefit of this SAMA is further reduced by the need for operator action (including local actions) for implementation.

SAMA Implementation Cost:

The cost of implementing this SAMA would be significant, involving (at a minimum) semi-permanent connection capability for D3 and/or D4 to the safeguards 4kV buses and analyses to show no degradation of the safeguards power supplies due to the modifications required. Procedures and operator training would need to be implemented to obtain much benefit from this SAMA. In addition, the reliability of D3 and D4 may need to be improved.

Recommendation:

Screen this SAMA from further consideration.

### F.5.2.4 SAMA 13 (Install Automatic Sump Pump for Zone 7 AB Flooding):

This SAMA attempts to address the risk of Auxiliary Building flooding (see SAMA 6 discussion above), which is dominated by floods in the lowest level (Zone 7, the 695’ elevation, represented by initiating events I-AB7FLDA and I-AB7FLDB). However, this SAMA addresses the problem by installing a sump pump system that would remove water from the affected area, providing additional time for operator action to isolate the break.

Risk Benefit:

The maximum risk benefit for this SAMA is low (see SAMA 6 discussion above).

SAMA Implementation Cost:

The cost of implementing this SAMA would be about the same, or slightly less, than the cost of SAMA 6, however, as with SAMA 6a, this SAMA relies on operator action to identify and isolate the header with the break (the current, pre-SAMA implementation situation). Therefore, a large portion of the risk benefit from this SAMA would not be realized. Also, even with successful operator action, the result is the loss of at least one train of safeguards equipment.

Recommendation:

Screen this SAMA from further consideration.

## F.6 PHASE II SAMA ANALYSIS

Not all of the Phase II SAMA candidates require detailed analysis. The Phase II process allows for the screening of SAMAs known to be related to non-risk significant systems or to components/functions with low importance rankings. Due to the nature of the PRA based process used to develop the PINGP SAMA list, there are limited avenues for SAMAs of this type to be included in the list. However, potential pathways do exist:

- Inclusion of unresolved proposed plant changes from previous PINGP risk analyses,
- Inclusion of SAMAs based on the results of conservative modeling methods.

While no calculations are required for eliminating a SAMA that is linked to a non-risk significant system or components, some quantitative efforts are usually required to screen SAMAs that were developed to address risk contributors based on conservative modeling techniques. These cases are identified in Table F.6-1 and discussed in detail in the SAMA specific subsections of F.6.

For the SAMAs requiring detailed analysis, a more detailed conceptual design was prepared along with a more detailed estimated cost. This information was then used to evaluate the effect of the candidates' changes upon the plant safety model.

The final cost-risk based screening method is defined by the following equation:

Net Value = (baseline cost-risk of plant operation (MMACR) – cost-risk of plant operation with SAMA implemented) – cost of implementation

If the net value of the SAMA is negative, the cost of implementation is larger than the benefit associated with the SAMA and the SAMA is not considered cost beneficial. The baseline cost-risk of plant operation was derived using the methodology presented in Section F.4. The cost-risk of plant operation with the SAMA implemented is determined in the same manner with the exception that the revised PRA results reflect implementation of the SAMA.

The implementation costs used in the Phase I and II analyses consist of PINGP specific estimates developed by plant personnel, as well as those from Sargent & Lundy for certain Phase II SAMAs (S&L 2007). The basic components of the cost estimates included relevant work activities across the following major project phases: study, analysis, design, implementation, and life cycle. Where possible, the economic benefit of implementing proposed SAMAs across both units and taking credit for certain duplicate work activities resulted in implementation costs for the second unit being reduced. To average this economic benefit across both units, the SAMA cost for each unit was figured by dividing the total expected cost by a factor of two. It should be noted that PINGP specific implementation costs do <u>not</u> account for any replacement power costs that may be incurred due to consequential shutdown time. Table F.5-3 provides implementation costs for each Phase I and II SAMA. Costs are delineated as ‘per unit’ and/or ‘total’ as appropriate.

Sections F.6.1 – F.6.14 describe the detailed cost-benefit analysis that was used for each of the remaining candidates. It should be noted that the release category results provided for each SAMA do not include contributions from the negligible release category.

### F.6.1 SAMA 2: Alternate Cooling Water (CL) Supply

Loss of the Cooling Water (CL) system is a highly risk-significant initiating event. Provision of an additional, alternate means of supplying CL may reduce the risk associated with these events. Although crossties from the fire protection system (FPS) are available, these crossties were intended to supply CL to FPS, not the other direction. As a result, the amount of water flow available from the FP system to CL may not be sufficient to meet the CL system needs, even for one train of safeguards equipment. Therefore, this SAMA investigates the risk impact of installing a redundant CL pump train, diverse and independent from the existing pump trains (for example, a separate diesel-driven CL pump located in a building onsite that can be tied into the existing system and will start automatically on low system pressure).

<u>Assumptions:</u>

1. For the purposes of this SAMA, it is assumed that the existing diesel-driven fire pump (DDFP) in the basement of the Screenhouse is upgraded and piped such that it can supply both the needs of the FP system and needs of the CL system (as a backup CL system pump).

2. The SAMA 2 pump would remain diesel-driven, with fuel, cooling and ventilation requirements independent of the diesel-driven cooling water pumps (DDCLPs), and would otherwise be diverse enough from the design of the existing DDCLPs such that no CCF potential existed between these pumps.

3. The suction source of the SAMA 2 pump is assumed to be the same suction source currently available to the DDFP (Unit 1 side Circ Water Bay).

4. The SAMA 2 pump is assumed to start automatically on low system pressure (when all of the other pumps have failed – setpoint below the current DDCLP start setpoint).

5. For operating flexibility, it was assumed that the SAMA 2 pump unavailability for testing or maintenance and existing CL pump unavailability for testing or maintenance are not mutually-exclusive events.

SAMA 2 pump failure modeling:

1. The pump FTR BE probability was determined by summing the diesel-driver and pump-portion FTR BE probabilities for one of the existing DDCLPs.

2. The pump FTS BE probability was determined by summing the diesel-driver and pump-portion FTS BE probabilities for one of the existing DDCLPs.

3. A double-check valve design on the outlet of the SAMA 2 pump was assumed in order to prevent a significant failure likelihood from flow diversion through the non-running pump (no such modeling was included in the fault tree).

4. It is assumed that the SAMA 2 pump discharge will be piped into the CL header similar to the location of 121 CL pump discharge, between the A/B and C/D header isolation MOVs, such that the pump is able to supply either CL header A or B on a unit SI signal. The existing FT models failure of one of these header isolation valves to remain open, together with failure of the remaining pumps available to that header to provide flow. However, due to the low risk significance of these failures, no additional modeling (to include the SAMA 2 pump failures) was felt to be necessary as this would only drive down the frequency of these sequences.

5. The fuel supply design for the SAMA 2 diesel engine was assumed to be similar (but independent) to that of the existing DDCLPs.

6. No failure basic events were included for pump ventilation issues over its mission time to run. The pump was assumed to have minimal ventilation requirements due to its location within the large, open Screenhouse basement room (or the ventilation design was assumed to have high reliability).

7. The design of the pump was assumed to not have a requirement for external bearing water cooling as the existing safeguards pumps have (pump has a self-sealing or other reliable seal design).

8. The SAMA 2 pump was assumed to be susceptible to failure from Screenhouse flooding initiating events.

9. The SAMA 2 pump was assumed to NOT be available as a safeguards (Technical Specifications) replacement for the existing DDCLPs (as the 121 motor-driven pump

is) since it is modeled as taking suction from the circulating water bay (not the safeguards pump bay).

PRA Model Changes to Model SAMA:

The table below provides a listing of the new basic events included in the PRA model for this sensitivity analysis:

**SAMA 2 New Basic Events**

| Description | Probability | Comments |
|---|---|---|
| SAMA DIESEL CL PUMP UNAVAILABLE DUE TO CORRECTIVE MAINTENANCE | 1.29E-03 | Assumes same unavailability as 12, 22 CL pumps |
| SAMA DIESEL CL PUMP UNAVAILABLE DUE TO PREVENTIVE MAINTENANCE | 1.58E-02 | Assumes same unavailability as 12, 22 CL pumps |
| SAMA 2 DIESEL CL PUMP FAILS TO RUN (24 HR MISSION) | 4.01E-02 | Probability derived by summing event probabilities for |
| SAMA 2 DIESEL CL PUMP FAILS TO START | 3.45E-03 | Probability derived by summing event probabilities for |
| SAMA 2 DIESEL CL PUMP OUT OF FUEL | 6.40E-03 | Probability determined by summing all BEs under 12 DDCLP. |
| SAMA 2 PUMP CHECK VALVE 1 FAILS TO OPEN | 5.00E-05 | Standard check valve FTO probability. |
| SAMA 2 PUMP CHECK VALVE 2 FAILS TO OPEN | 5.00E-05 | Standard check valve FTO probability. |

Results of SAMA Quantification:

Implementation of this SAMA yields a reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk (OECR). The results are summarized in the following table for Units 1 and 2:

| | CDF | Dose-Risk | OECR |
|---|---|---|---|
| Unit $1_{Base}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit $1_{SAMA}$ | 7.72E-06 | 2.73 | $15,396 |
| Unit 1 Percent Reduction | 21.2% | 6.8% | 2.9% |
| Unit $2_{Base}$ | 1.21E-05 | 8.43 | $63,337 |
| Unit $2_{SAMA}$ | 1.00E-05 | 8.22 | $62,884 |
| Unit 2 Percent Reduction | 17.1% | 2.5% | 0.7% |

**SAMA 2 - Unit 1 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Frequency_{SAMA}$ | 7.02E-06 | 1.82E-07 | 2.64E-07 | 2.27E-07 | 4.89E-08 | 3.22E-08 | 2.45E-09 | 4.84E-09 | 8.40E-10 | 2.32E-11 | **7.72E-06** |
| Dose-$Risk_{BASE}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| Dose-$Risk_{SAMA}$ | 0.01 | 0.01 | 0.59 | 1.29 | 0.10 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.73** |
| $OECR_{BASE}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |
| $OECR_{SAMA}$ | $0 | $2 | $900 | $11,422 | $646 | $2,408 | $0 | $0 | $18 | $0 | **$15,396** |

**SAMA 2 - Unit 2 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.21E-05** |
| $Frequency_{SAMA}$ | 8.28E-06 | 2.18E-07 | 3.23E-07 | 1.16E-06 | 5.79E-08 | 3.22E-08 | 2.80E-09 | 5.82E-09 | 9.17E-10 | 2.32E-11 | **1.00E-05** |
| Dose-$Risk_{BASE}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.43** |
| Dose-$Risk_{SAMA}$ | 0.01 | 0.01 | 0.72 | 6.63 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.22** |
| $OECR_{BASE}$ | $0 | $19 | $1,157 | $58,874 | $860 | $2,408 | $0 | $0 | $19 | $0 | **$63,337** |
| $OECR_{SAMA}$ | $0 | $2 | $1,101 | $58,589 | $765 | $2,408 | $0 | $0 | $19 | $0 | **$62,884** |

This information was used in the cost-benefit calculation. The results of this calculation are provided in the following table.

**SAMA 2 Net Value**

| Unit | Base Case Cost-Risk | Revised Cost-Risk | Averted Cost-Risk |
|---|---|---|---|
| Unit 1 | $1,114,000 | $990,624 | $123,376 |
| Unit 2 | $2,980,000 | $2,856,908 | $123,092 |

The SAMA 2 results indicate a relatively significant reduction in CDF. Most of the CDF reduction is due to the decrease in the frequency of release category L-DH-L (late vessel failure with late containment failure due to failure of containment heat removal); however, this category is not very significant to the overall risk from offsite releases.

Based on a $300,000 cost of implementation for each unit, the net value for this SAMA is -$176,624 ($123,376 - $300,000) for Unit 1 and -$176,908 ($123,092 - $300,000) for Unit 2, which implies that this SAMA is not cost beneficial for either unit.

### F.6.2 SAMA 3: Provide Alternate Flow Path from RWST to Charging Pump Suction

In the PINGP PRA model, failure to maintain cooling to the reactor coolant pump (RCP) seal package is assumed to result in a small LOCA through the RCP seals. The normal means of providing seal cooling during plant operation is through RCP seal injection from the Chemical and Volume Control System (CVCS) charging pumps. Water for seal injection is taken from the Volume Control Tank (VCT) and pumped into the RCP seal packages by the charging pumps. On low VCT level, the charging pump suction is automatically supplied from the RWST (VCT isolation MOV closes and RWST MOV opens). The current plant design provides only one flow path from the RWST to charging. This SAMA investigates the risk benefit of adding a bypass line around the motor-operated valve that must open to supply charging pump suction flow from the RWST upon loss of VCT level (MV-32060 for Unit 1, MV-32062 for Unit 2).

Assumptions:

1. The bypass line for each unit is assumed to contain a normally closed, fail closed air-operated valve that opens on low VCT level (same instrumentation that provides open signal to the MOV).

2. The bypass line air operated valve (AOV) is assumed to be supplied with an air accumulator in the event that normal plant instrument air is lost (due to the high reliability of such an air supply system, no air dependency is modeled in the fault tree). The purpose of this design requirement is to eliminate the common

dependency of the Component Cooling Water (CC) system and the Instrument Air (SA) system on the Cooling Water (CL) system. As CC is a backup for seal cooling in the event of loss of seal injection flow from the charging pumps, the elimination of this dependency is critical to obtaining maximum value from this SAMA.

PRA Model Changes to Model SAMA:

The table below provides a listing of the new basic events included in the PRA model for this sensitivity analysis:

**SAMA 3 New Basic Events**

| Description | Probability | Comments |
|---|---|---|
| SAMA 3 AIR OPERATED VALVE FAILS TO OPEN | 3.00E-03 | Standard air-operated valve FTO probability. |
| SAMA 3 AIR OPERATED VALVE FAILS TO REMAIN OPEN | 1.01E-05 | Standard air-operated valve FTRO probability. Assumes standard 24-hour mission time. |

Results of SAMA Quantification:

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table for Units 1 and 2:

| | CDF | Dose-Risk | OECR |
|---|---|---|---|
| Unit $1_{Base}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit $1_{SAMA}$ | 8.52E-06 | 2.83 | $15,548 |
| Unit 1 Percent Reduction | 13.0% | 3.4% | 1.9% |
| Unit $2_{Base}$ | 1.21E-05 | 8.43 | $63,337 |
| Unit $2_{SAMA}$ | 1.08E-05 | 8.32 | $63,030 |
| Unit 2 Percent Reduction | 10.7% | 1.3% | 0.5% |

A further breakdown of the Dose-risk and OECR information is provided below according to release category.

**SAMA 3 - Unit 1 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Frequency_{SAMA}$ | 7.17E-06 | 7.85E-07 | 2.82E-07 | 2.29E-07 | 4.95E-08 | 3.22E-08 | 1.12E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **8.52E-06** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.05 | 0.63 | 1.30 | 0.11 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.83** |
| $OECR_{BASE}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |
| $OECR_{SAMA}$ | $0 | $8 | $961 | $11,500 | $653 | $2,408 | $0 | $0 | $18 | $0 | **$15,548** |

**SAMA 3 - Unit 2 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.21E-05** |
| $Frequency_{SAMA}$ | 8.41E-06 | 8.14E-07 | 3.39E-07 | 1.17E-06 | 5.85E-08 | 3.22E-08 | 1.15E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.08E-05** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.43** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.05 | 0.76 | 6.64 | 0.13 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.32** |
| $OECR_{BASE}$ | $0 | $19 | $1,157 | $58,874 | $860 | $2,408 | $0 | $0 | $19 | $0 | **$63,337** |
| $OECR_{SAMA}$ | $0 | $8 | $1,157 | $58,666 | $772 | $2,408 | $0 | $0 | $19 | $0 | **$63,030** |

This information was used in the cost-benefit calculation. The results of this calculation are provided in the following table.

**SAMA 3 Net Value**

| Unit | Base Case Cost-Risk | Revised Cost-Risk | Averted Cost-Risk |
|---|---|---|---|
| Unit 1 | $1,114,000 | $1,039,044 | $74,956 |
| Unit 2 | $2,980,000 | $2,903,346 | $76,654 |

The SAMA 3 results are similar to the SAMA 2 results, although the magnitude of the reductions in CDF and LERF are slightly lower. Both SAMAs act to reduce the potential for RCP seal LOCA-induced core damage, however, addition of the diverse CL pump of SAMA 2 provides additional benefits that the more focused SAMA 3 does not provide. Most of the CDF reduction is due to the decrease in the frequency of release category L-DH-L (late vessel failure with late containment failure due to failure of containment heat removal), however, this category is not very significant to the overall risk from offsite releases. The small drop seen in release category L-SR-E (pressure or temperature-induced SGTR), a component of the LERF, is the most significant risk benefit associated with this SAMA.

Based on a $250,000 cost of implementation for each unit, the net value for this SAMA is -$175,044 ($74,956 - $250,000) for Unit 1 and -$173,346 ($76,654 - $250,000) for Unit 2, which implies that this SAMA is <u>not</u> cost beneficial for either unit.

### F.6.3 SAMA 5: Diesel-Driven HPI Pump

SAMA 5 investigates the potential risk reduction for installing an additional diesel-driven, high pressure injection (HPI) pump that could use a large volume, cold suction source. The intent of this SAMA is to reduce the risk of Station Blackout events (by prolonging the time the plant can operate without AC power) and SGTR events (by providing a diverse means of providing high pressure injection from the RWST). No containment sump recirculation capability was assumed for this pump train.

Assumptions:

An additional, diesel-driven HPI pump train is assumed to be made available to the ECCS, in parallel to the two existing SI pumps on both units (the SAMA 5 pump would be common to both units).

The following additional assumptions are made regarding this pump train:

1. The initial suction source to the SAMA 5 pump train is assumed to be the RWST. However, it is assumed that the design allows for highly reliable, automatic transfer to an alternate supply (other unit RWST, BAST, SFP, etc.) on loss of RWST level. (NOTE: This design addresses SAMA 19a as well).
    a. Use of a river water source, while having the advantage of unlimited supply, is assumed to not be a viable alternative as it is not a borated water source.
2. The SAMA 5 pump train is assumed to be independent of the existing SI pumps both in design (including location) and operation such that the potential for common cause failures associated with all three HPI pump trains is negligible. The pump train is also assumed to be of a design that is diverse from the existing diesel CL pump trains.
3. The SAMA 5 pump train is assumed to be supplied with water for pump cooling by either train (header) of the site cooling water system (provides some diversity from the CC system means of equipment heat removal used by the existing SI pumps). A normally-open MOV is assumed for isolation (must remain open during pump mission time to run).
    a. Self cooling (through recirculation of borated RWST water) is not considered to be a viable alternative.
4. The SAMA 5 pump train is assumed to start on an S-signal for either train/either unit and run on recirculation until flow is lost from the SI pump trains on the affected unit. The shutoff head for the SAMA 5 pump train is slightly lower than the SI pumps, such that it will automatically supply HPI flow should flow from the SI pump trains on the affected unit be lost.
5. The SAMA 5 pump train is assumed to either be provided with a highly reliable ventilation system, or be located in a large volume such that pump train failures due to ventilation failures are not likely.

6. For operating flexibility, it was assumed that the SAMA 5 pump unavailability for testing or maintenance and existing SI pump unavailability for testing or maintenance are not mutually-exclusive events.

SAMA 5 pump failure modeling:

1. The SAMA 5 pump FTR BE probability was determined by summing the diesel-driver and pump-portion FTR BE probabilities for one of the existing DDCLPs.
2. The SAMA 5 pump FTS BE probability was determined by summing the diesel-driver and pump-portion FTS BE probabilities for one of the existing DDCLPs.
3. A check valve on the outlet of the SAMA 5 pump was assumed to be required in order to prevent a significant failure likelihood from flow diversion through the pump should it fail to start (no such modeling was included in the fault tree).
4. It is assumed that the SAMA 5 pump discharge will be piped into the high head safety injection (HHSI) header in the section of SI pump discharge piping common to both existing pump trains, such that the SAMA 5 pump is able to supply either the A or B HPI header on a unit SI signal.
5. The fuel supply design for the SAMA 5 diesel engine was assumed to be similar (but independent) to that of the existing DDCLPs.

PRA Model Changes to Model SAMA:

The table below provides a listing of the new basic events included in the PRA model for this sensitivity analysis:

**SAMA 5 New Basic Events**

| Description | Probability | Comments |
|---|---|---|
| SAMA 5 HP INJECTION PUMP FAILS TO RUN | 4.01E-02 | Probability determined by summing the CLP diesel-driver and pump-portion FTR BE |
| SAMA 5 HP INJECTION PUMP FAILS TO START | 3.45E-03 | Probability determined by summing the CLP diesel-driver and pump-portion FTS BE |
| SAMA 2 DIESEL HPI PUMP UNAVAILABLE DUE TO CORRECTIVE MAINTENANCE | 1.29E-03 | Assumes same unavailability as 12, 22 CL pumps |
| SAMA 2 DIESEL HPI PUMP UNAVAILABLE DUE TO PREVENTIVE MAINTENANCE | 1.58E-02 | Assumes same unavailability as 12, 22 CL pumps |
| SAMA 2 DIESEL HPI PUMP OUT OF FUEL | 6.40E-03 | Probability determined by summing all BEs under 12 DDCLP. |
| SAMA 5 DIESEL HPI PUMP DISCHARGE CHECK VALVE FAILS TO OPEN | 5.00E-05 | Standard check valve FTO probability. |
| SAMA 5 PUMP COOLING WATER MOTOR OPERATED ISOLATION VALVE FTRO | 4.80E-06 | Standard motor-operated valve FTRO probability. Assumes standard 24 hour mission time. |

Results of SAMA Quantification:

Implementation of this SAMA yields a slight reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table for Units 1 and 2:

| | **CDF** | **Dose-Risk** | **OECR** |
|---|---|---|---|
| Unit $1_{Base}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit $1_{SAMA}$ | 9.77E-06 | 2.39 | $14,450 |
| Unit 1 Percent Reduction | 0.3% | 18.4% | 8.8% |
| Unit $2_{Base}$ | 1.21E-05 | 8.43 | $63,337 |
| Unit $2_{SAMA}$ | 1.20E-05 | 7.37 | $58,219 |
| Unit 2 Percent Reduction | 0.8% | 12.6% | 8.1% |

A further breakdown of the Dose-risk and OECR information is provided below according to release category.

**SAMA 5 - Unit 1 Results By Release Category**

| **Release Category** | **H-XX-X** | **L-DH-L** | **L-CC-L** | **SGTR** | **L-H2-E** | **ISLOCA** | **H-DH-L** | **H-OT-L** | **L-CI-E** | **H-H2-E** | **Total** |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Frequency_{SAMA}$ | 7.51E-06 | 1.92E-06 | 6.95E-08 | 2.21E-07 | 5.09E-08 | 3.22E-08 | 3.06E-08 | 5.45E-10 | 8.40E-10 | 0.00E+00 | **9.77E-06** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.12 | 0.16 | 1.26 | 0.11 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.39** |
| $OECR_{BASE}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |
| $OECR_{SAMA}$ | $0 | $18 | $237 | $11,098 | $671 | $2,408 | $0 | $0 | $18 | $0 | **$14,450** |

**SAMA 5 - Unit 2 Results By Release Category**

| **Release Category** | **H-XX-X** | **L-DH-L** | **L-CC-L** | **SGTR** | **L-H2-E** | **ISLOCA** | **H-DH-L** | **H-OT-L** | **L-CI-E** | **H-H2-E** | **Total** |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.21E-05** |
| $Frequency_{SAMA}$ | 8.74E-06 | 2.02E-06 | 7.99E-08 | 1.09E-06 | 5.99E-08 | 3.22E-08 | 3.11E-08 | 6.02E-10 | 9.17E-10 | 0.00E+00 | **1.20E-05** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.43** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.13 | 0.18 | 6.19 | 0.13 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **7.37** |
| $OECR_{BASE}$ | $0 | $19 | $1,157 | $58,874 | $860 | $2,408 | $0 | $0 | $19 | $0 | **$63,337** |
| $OECR_{SAMA}$ | $0 | $19 | $272 | $54,710 | $791 | $2,408 | $0 | $0 | $19 | $0 | **$58,219** |

This information was used in the cost-benefit calculation. The results of this calculation are provided in the following table.

**SAMA 5 Net Value**

| Unit | Base Case Cost-Risk | Revised Cost-Risk | Averted Cost-Risk |
|---|---|---|---|
| Unit 1 | $1,114,000 | $1,038,058 | $75,942 |
| Unit 2 | $2,980,000 | $2,757,390 | $222,610 |

The SAMA 5 results show a reduction in the potential for core damage with containment bypass due to SGTR events. This is due to the ability to align an alternate, diverse pump train to supply RCS makeup following a SGTR, in the event that both safety injection pump trains are unavailable or failed. The independence of the pump from the component cooling system also provides a significant risk benefit. Also, the beneficial impact of this SAMA is greater for Unit 2, which has a higher potential for SGTR events (SGs have not been replaced on Unit 2 as they have on Unit 1). However, the high cost of this modification is not offset by the expected risk benefit from either unit.

Based on a $1,500,000 cost of implementation for each unit, the net value for this SAMA is -$1,424,058 ($75,942 - $1,500,000) for Unit 1 and -$1,277,390 ($222,610 - $1,500,000) for Unit 2, which implies that this SAMA is <u>not</u> cost beneficial for either unit.

### F.6.4 SAMA 9: Analyze Room Heat-up for Natural/Forced Circulation (Screenhouse Ventilation)

The purpose of this SAMA is to investigate the risk benefit of implementing procedural practices (opening doors, installing portable fans) or a plant modification to improve ventilation for safeguards equipment in the screenhouse. In particular, failures of the ventilation system associated with the safeguards vertical cooling water (CL) pumps currently provide a significant contribution to plant core damage risk. This SAMA determines the maximum benefit achievable if the Screenhouse ventilation system reliability is improved.

<u>Assumptions:</u>

1. It is assumed that the implementation of this SAMA either:

    a. allows all combinations of running safeguards CL pumps to run for at least a 24-hour mission time without forced ventilation (and with room temperatures stable or trending lower at 24 hours), or

    b. increases the reliability of the Screenhouse ventilation system such that the potential for loss of running safeguards CL pumps provides a negligible contribution to plant risk.

2. For the purposes of SAMA cost estimation, it is assumed that a best-estimate room heatup analysis (the least expensive option) is chosen, and that the reanalysis provides results that adequately support Assumption 1a above.

<u>PRA Model Changes to Model SAMA:</u>

In order to model this SAMA, all of the PRA fault tree model logic associated with failures of the safeguards vertical CL pumps (12, 121, and 22) due to Screenhouse ventilation system failures was set to logical FALSE. This treatment demonstrates the maximum risk benefit of this SAMA.

<u>Results of SAMA Quantification:</u>

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table for Units 1 and 2:

| | CDF | Dose-Risk | OECR |
|---|---|---|---|
| Unit $1_{Base}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit $1_{SAMA}$ | 8.75E-06 | 2.83 | $15,600 |
| Unit 1 Percent Reduction | 10.7% | 3.4% | 1.6% |
| Unit $2_{Base}$ | 1.21E-05 | 8.43 | $63,337 |
| Unit $2_{SAMA}$ | 1.10E-05 | 8.32 | $63,088 |
| Unit 2 Percent Reduction | 8.6% | 1.3% | 0.4% |

A further breakdown of the Dose-risk and OECR information is provided below according to release category.

**SAMA 9 - Unit 1 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Frequency_{SAMA}$ | 7.24E-06 | 9.47E-07 | 2.79E-07 | 2.29E-07 | 5.16E-08 | 3.22E-08 | 1.39E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **8.75E-06** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.06 | 0.62 | 1.30 | 0.11 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.83** |
| $OECR_{BASE}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |
| $OECR_{SAMA}$ | $0 | $9 | $953 | $11,531 | $681 | $2,408 | $0 | $0 | $18 | $0 | **$15,600** |

**SAMA 9 - Unit 2 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.21E-05** |
| $Frequency_{SAMA}$ | 8.49E-06 | 9.92E-07 | 3.38E-07 | 1.17E-06 | 6.06E-08 | 3.22E-08 | 1.44E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.10E-05** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.43** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.06 | 0.75 | 6.64 | 0.13 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.32** |
| $OECR_{BASE}$ | $0 | $19 | $1,157 | $58,874 | $860 | $2,408 | $0 | $0 | $19 | $0 | **$63,337** |
| $OECR_{SAMA}$ | $0 | $10 | $1,151 | $58,700 | $800 | $2,408 | $0 | $0 | $19 | $0 | **$63,088** |

This information was used in the cost-benefit calculation. The results of this calculation are provided in the following table.

**SAMA 9 Net Value**

| Unit | Base Case Cost-Risk | Revised Cost-Risk | Averted Cost-Risk |
|---|---|---|---|
| Unit 1 | $1,114,000 | $1,051,254 | $62,746 |
| Unit 2 | $2,980,000 | $2,917,082 | $62,918 |

The SAMA 9 risk reduction results are similar to the SAMA 3 results, both in magnitude and in release categories benefited. SAMA 9 also reduces the potential for seal LOCAs, as the availability of the CL system is enhanced, although it also has the potential to reduce the loss of cooling water (LOCL) initiating event frequency. The impact of eliminating the Screenhouse ventilation dependency is not as great as the impact of adding another diverse CL pump, however (SAMA 2).

Based on a $62,500 cost of implementation for each unit, the net value for this SAMA is $246 ($62,746 - $62,500) for Unit 1 and $418 ($62,918 - $62,500) for Unit 2, which implies that this SAMA is cost beneficial for both units.

### F.6.5 SAMA 12: Alternate Component Cooling Water Supply

The Component Cooling Water (CC) system provides cooling for the ECCS and other safeguards components, and provides a backup to the Chemical and Volume Control System (CVCS) seal injection system for cooling the reactor coolant pump (RCP) seals. The purpose of this SAMA is to investigate the risk benefit of enabling an alternate means of supplying water to the Component Cooling Water (CC) system.

The most risk-significant events associated with the CC system are those in which the entire system is lost (loss of CC initiating event, or those initiated by other events, but in which both CC pump trains subsequently fail to supply flow for mitigation of the event).

Therefore, any alternate CC supply source should provide sufficient flow to support the removal of heat through the CC heat exchangers.

In addition to pump train failures, passive CC system piping and head tank faults contribute to potential for loss of the CC system, although only the head tank faults contribute significantly to the initiating event frequency. These passive faults must be isolatable in order to maintain flow to the supplied equipment.

Normal makeup to the CC system is from the reactor makeup water (RM) system. Makeup from RM system is low-volume and intended only for minor makeup requirements to the closed-loop CC system. Therefore, an alternate source of water is necessary for this SAMA. The CCW pumps and heat exchangers are located on the 695' elevation of the Auxiliary Building. Available alternate supply sources in this location include headers include the CL and Fire Protection (FP) system piping. These alternate makeup sources are not closed loop systems. Therefore, use of these systems will require availability of a system outlet (note that this outlet flow will also provide additional heat removal for the system).

The CL system currently provides the ultimate heat sink for the CC system through the CC heat exchangers. Therefore, if the FP system is used as the alternate CC system supply the design should either provide an alternate means of system heat removal, or should ensure that a sufficient amount of flow is available to circulate water through the CC heat exchangers for significant heat removal to the CL system (to avoid rejection of an excessive amount of heat through the existing FP discharge piping). If the CL system is used as the alternate CC system supply the design may require the addition of CL pumping capacity to maintain design requirements.

<u>Assumptions:</u>

1. Neither the existing CL system nor the existing FP is assumed to be a viable source of alternate supply water to the CC system without additional flow capacity. One possibility may be to combine SAMA 2 (which investigates upgrading the existing diesel-driven fire pump and using it as an additional backup CL pump train) to this SAMA in order to achieve the benefits from both. For the purposes of this SAMA, the CL system upgrade, as described for SAMA 2, is assumed to have been performed (with SAMA 12 design requirements also incorporated).

2. It is assumed that an automatic means of supplying water from the alternate train upon loss of CC system flow (loss of flow, loss of pressure, and/or other signal, such as both CC pumps tripped) is available. A normally-closed MOV for each CC header (A or B) is assumed to be required to open in order to provide this supply. A

return MOV from each header is also assumed to be required to open to provide the return path from the CC system to the CL return header.

3. It is assumed that an attempt to limit the potential for MOV common cause failures, resulting in the loss of the entire alternate CC supply, is made in the SAMA 12 design process. Therefore, CCF of the CL supply and return MOVs to open are modeled across trains, but not across supply/return applications (i.e., the Train A and Train B supply MOVs are modeled as having the potential for CCF, but the Train A supply and Train B return MOVs are not).

4. Except for the loss of all CL initiating event (I-LOCL), failures involving flow from the CL system headers are not modeled under the alternate supply logic, because loss of flow from these headers will directly result in loss of the affected CC train (due to loss of CL flow to the associated CC heat exchanger). Due to flagging issues, the I-LOCL event must be included as a failure of the SAMA 12 alternate supply in order for the model to quantify correctly.

5. Internal flooding events in the 695’ elevation of the Auxiliary Building are assumed to be due to failures of CL system piping in the CC pump/heat exchanger room. Therefore, these initiating events are included as failures of the SAMA 12 alternate CC supply.

6. Rupture of the CC surge tank on a given unit is modeled as a failure of all component cooling water for that unit in the current PRA revision (no credit is given for operator action to isolate the break and to operate either train of the CC system without an expansion volume). This assumption is maintained for the SAMA 12 quantification; however, if the CC surge tank failure is manually isolated (using the CC pump suction isolation MOVs, which can be operated from the control room), then the alternate SAMA 12 supply from the CL system should not be impacted. Credit for operator identification and manual isolation of the surge tank rupture event is given in the model.

PRA Model Changes to Model SAMA 12:

The table below provides a listing of the new basic events included in the PRA model for this sensitivity analysis:

**SAMA 12 New Basic Events**

| Description | Probability | Comments |
|---|---|---|
| OPERATOR FAILS TO ISOLATE CC SURGE TANK RUPTURE | 5.00E-2 | Standard HRA screening value. |
| UNIT 1 TRAIN A SAMA 12 SUPPLY MOV FAILS TO OPEN | 2.88E-03 | Standard motor operated valve FTO probability. |
| UNIT 1 TRAIN A SAMA 12 SUPPLY MOV FAILS TO REMAIN OPEN | 4.80E-06 | Standard motor operated valve FTRO probability. Assumes standard 24-hour mission time. |
| UNIT 1 SAMA 12 CL TRAIN A AND B SUPPLY MOVs FTO DUE TO CCF | 1.23E-04 | Standard motor operated valve FTO CCF probability. |
| UNIT 1 TRAIN A SAMA 12 RETURN MOV FAILS TO OPEN | 2.88E-03 | Standard motor operated valve FTO probability. |
| UNIT 1 TRAIN A SAMA 12 RETURN MOV FAILS TO REMAIN OPEN | 4.80E-06 | Standard motor operated valve FTRO probability. Assumes standard 24-hour mission time. |
| UNIT 1 SAMA 12 CL TRAIN A AND B RETURN MOVs FTO DUE TO CCF | 1.23E-04 | Standard motor operated valve FTO CCF probability. |
| MV-32200 (11 CC SURGE TANK TO 11 CC PUMP) FAILS TO CLOSE | 2.94E-03 | Standard motor operated valve FTC probability. |
| MV-32201 (11 CC SURGE TANK TO 12 CC PUMP) FAILS TO CLOSE | 2.94E-03 | Standard motor operated valve FTC probability. |
| MV-32200 & MV-32201 FTC DUE TO CCF (CC SURGE TANK ISOLATION MOVs) | 6.21E-05 | Standard motor operated valve FTC CCF probability. |
| UNIT 1 TRAIN B SAMA 12 SUPPLY MOV FAILS TO OPEN | 2.88E-03 | Standard motor operated valve FTO probability. |
| UNIT 1 TRAIN B SAMA 12 SUPPLY MOV FAILS TO REMAIN OPEN | 4.80E-06 | Standard motor operated valve FTRO probability. Assumes standard 24-hour mission time. |
| UNIT 1 TRAIN B SAMA 12 RETURN MOV FAILS TO OPEN | 2.88E-03 | Standard motor operated valve FTO probability. |
| UNIT 1 TRAIN B SAMA 12 RETURN MOV FAILS TO REMAIN OPEN | 4.80E-06 | Standard motor operated valve FTRO probability. Assumes standard 24-hour mission time. |
| UNIT 2 TRAIN A SAMA 12 SUPPLY MOV FAILS TO OPEN | 2.88E-03 | Standard motor operated valve FTO probability. |
| UNIT 2 TRAIN A SAMA 12 SUPPLY MOV FAILS TO REMAIN OPEN | 4.80E-06 | Standard motor operated valve FTRO probability. Assumes standard 24-hour mission time. |
| UNIT 2 SAMA 12 CL TRAIN A AND B SUPPLY MOVs FTO DUE TO CCF | 1.23E-04 | Standard motor operated valve FTO CCF probability. |
| UNIT 2 TRAIN A SAMA 12 RETURN MOV FAILS TO OPEN | 2.88E-03 | Standard motor operated valve FTO probability. |
| UNIT 2 TRAIN A SAMA 12 RETURN MOV FAILS TO REMAIN OPEN | 4.80E-06 | Standard motor operated valve FTRO probability. Assumes standard 24-hour mission time. |
| UNIT 2 SAMA 12 CL TRAIN A AND B RETURN MOVs FTO DUE TO CCF | 1.23E-04 | Standard motor operated valve FTO CCF probability. |
| MV-32211 (21 CC SURGE TANK TO 21 CC PUMP) FAILS TO CLOSE | 2.94E-03 | Standard motor operated valve FTC probability. |
| MV-32212 (21 CC SURGE TANK TO 22 CC PUMP) FAILS TO CLOSE | 2.94E-03 | Standard motor operated valve FTC probability. |
| MV-32200 & MV-32201 FTC DUE TO CCF (CC SURGE TANK ISOLATION MOVs) | 6.21E-05 | Standard motor operated valve FTC CCF probability. |
| UNIT 2 TRAIN B SAMA 12 SUPPLY MOV FAILS TO OPEN | 2.88E-03 | Standard motor operated valve FTO probability. |
| UNIT 2 TRAIN B SAMA 12 SUPPLY MOV FAILS TO REMAIN OPEN | 4.80E-06 | Standard motor operated valve FTRO probability. Assumes standard 24-hour mission time. |
| UNIT 1 TRAIN B SAMA 12 RETURN MOV FAILS TO OPEN | 2.88E-03 | Standard motor operated valve FTO probability. |
| UNIT 2 TRAIN B SAMA 12 RETURN MOV FAILS TO REMAIN OPEN | 4.80E-06 | Standard motor operated valve FTRO probability. Assumes standard 24-hour mission time. |

Results of SAMA Quantification:

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table for Units 1 and 2:

| | CDF | Dose-Risk | OECR |
|---|---|---|---|
| Unit $1_{Base}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit $1_{SAMA}$ | 6.85E-06 | 2.67 | $14,791 |
| Unit 1 Percent Reduction | 30.1% | 8.9% | 6.7% |
| Unit $2_{Base}$ | 1.21E-05 | 8.43 | $63,337 |
| Unit $2_{SAMA}$ | 9.01E-06 | 7.74 | $59,428 |
| Unit 2 Percent Reduction | 25.2% | 8.2% | 6.2% |

A further breakdown of the Dose-risk and OECR information is provided below according to release category.

**SAMA 12 - Unit 1 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Frequency_{SAMA}$ | 6.15E-06 | 1.63E-07 | 2.64E-07 | 2.17E-07 | 4.09E-08 | 3.22E-08 | 2.13E-09 | 4.84E-09 | 8.40E-10 | 2.32E-11 | **6.85E-06** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.01 | 0.59 | 1.24 | 0.09 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.67** |
| $OECR_{BASE}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |
| $OECR_{SAMA}$ | $0 | $2 | $900 | $10,923 | $540 | $2,408 | $0 | $0 | $18 | $0 | **$14,791** |

**SAMA 12 - Unit 2 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.21E-05** |
| $Frequency_{SAMA}$ | 7.41E-06 | 1.95E-07 | 2.73E-07 | 1.10E-06 | 4.97E-08 | 3.22E-08 | 2.48E-09 | 4.87E-09 | 9.17E-10 | 2.32E-11 | **9.01E-06** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.43** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.01 | 0.61 | 6.27 | 0.11 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **7.74** |
| $OECR_{BASE}$ | $0 | $19 | $1,157 | $58,874 | $860 | $2,408 | $0 | $0 | $19 | $0 | **$63,337** |
| $OECR_{SAMA}$ | $0 | $2 | $931 | $55,413 | $655 | $2,408 | $0 | $0 | $19 | $0 | **$59,428** |

This information was used in the cost-benefit calculation. The results of this calculation are provided in the following table.

**SAMA 12 Net Value**

| Unit | Base Case Cost-Risk | Revised Cost-Risk | Averted Cost-Risk |
|---|---|---|---|
| Unit 1 | $1,114,000 | $927,812 | $186,188 |
| Unit 2 | $2,980,000 | $2,677,868 | $302,132 |

As expected, the results of the SAMA 12 risk benefit quantification exceed those of SAMA 2, as this alternative also assumes the implementation of SAMA 2, but also provides a backup supply of water to the CC header for safeguards equipment heat removal. A significant additional decrease is seen in CDF, primarily due to reduction in the frequency of loss of CC (LOCC) initiating events that lead to core damage without containment failure (release categories X-XX-X and L-XX-X). However, the significant benefit added by SAMA 12 is in the additional large drop in the frequency of release category GEH (SGTR with early core damage at high reactor pressure). This is due to the dependence of the high head injection system (SI system) on CC for equipment heat removal. SGTR events without high head injection capability are assumed to lead to the GEH accident class, unless the operators manage to depressurize the primary system to below the secondary side pressure (stop the primary to secondary leak) prior to overfilling the faulted steam generator. The beneficial impact of this SAMA is even greater for Unit 2, which has a higher potential for SGTR events (SGs have not been replaced on Unit 2 as they have on Unit 1).

Based on a $900,000 cost of implementation for each unit, the net value for this SAMA is -$713,812 ($186,188 - $900,000) for Unit 1 and -$597,868 ($302,132 - $900,000) for Unit 2, which implies that this SAMA is <u>not</u> cost beneficial for either unit.

### F.6.6 SAMA 15: Portable DC Power Source

The reliability of Unit 2 Train A DC power (DC Panel 21) has a higher importance to the risk of a core damaging event on its dedicated unit (Unit 2) than do any of the other DC power trains. Loss of Train A DC on either unit results in the loss of all main feedwater, and the loss of instrument air to containment (important for bleed and feed operation of the RCS PORVs). However, unlike Unit 1, the Unit 2 motor-driven AFW pump (21 AFW pump), powered from 4160 V AC Bus 25, is also dependent on Train A DC for breaker control power. Therefore, on a loss of Unit 2 Train A DC power initiating event, if the Unit 2 turbine-driven AFW pump fails to start or run, only operator action is available to prevent core damage (local action to restore an AFW pump, or action from the control room to perform bleed and feed). Note that, on this event, the reliability of the bleed and feed action is potentially impacted as the PORV operation must rely on PORV air accumulators that have not been positively tested under a complete range of potential bleed and feed scenarios.

Assumptions:

1. It is assumed that the primary DC backup supply for 21 AFW pump breaker control power is provided by a battery bank, with a failure rate similar to the existing safeguards (i.e., 21 and 22) batteries.
2. The SAMA 15 battery bank is assumed to be operable whenever the 21 AFW pump is required to be operable.
3. The SAMA 15 battery bank has no common-cause failure potential with any of the existing safeguards batteries.
4. Due to the relatively high reliability of the battery source, no credit for the SAMA 15 battery charger as a DC power source is included in the modeling.

PRA Model Changes to Model SAMA:

As described above, the unavailability of the 21 AFW pump auto-start capability is the primary risk contributor on a loss of Unit 2 Train A DC power. Although a modification providing additional DC power backup to Panel 21 (possibly from an independent and remotely-located source) would be a more comprehensive means of implementing this SAMA, this would require a larger DC power supply and a potentially much more expensive modification than would providing Bus 25 control power. However, a study of the Unit 2 CDF cutsets shows that loss of DC control power to the other loads on this bus provides very little contribution to CDF (all DC power-related failures in the cutset file not associated with the loss of DC initiating event are panel circuit (fuse) failures unrelated to Bus 25 breaker control power). As the DC control power requirement is only required to close the breaker one time during an accident condition, this DC supply could be provided by a small battery bank receiving a continuous "trickle" charge during normal operation. Therefore, to simplify the PRA modeling of this SAMA, the backup DC power source will be applied to only the 21 AFW pump control power logic. The table below provides a listing of the new basic events included in the PRA model for this sensitivity analysis:

**SAMA 15 New Basic Events**

| Description | Probability | Comments |
|---|---|---|
| SAMA 15 BATTERY FAILS ON DEMAND | 3.95E-04 | Standard battery failure on demand probability. |

Results of SAMA Quantification:

Implementation of this SAMA yields a slight reduction in the Unit 2 CDF, Dose-risk, and Offsite Economic cost-risk only. The results are summarized in the following table for Units 1 and 2:

| | CDF | Dose-Risk | OECR |
|---|---|---|---|
| Unit $1_{Base}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit $1_{SAMA}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit 1 Percent Reduction | 0.0% | 0.0% | 0.0% |
| Unit $2_{Base}$ | 1.21E-05 | 8.43 | $63,337 |
| Unit $2_{SAMA}$ | 1.17E-05 | 8.41 | $63,260 |
| Unit 2 Percent Reduction | 2.8% | 0.3% | 0.1% |

A further breakdown of the Dose-risk and OECR information is provided below according to release category.

**SAMA 15 - Unit 1 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Frequency_{SAMA}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| $OECR_{BASE}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |
| $OECR_{SAMA}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |

**SAMA 15 - Unit 2 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.21E-05** |
| $Frequency_{SAMA}$ | 8.20E-06 | 1.96E-06 | 3.39E-07 | 1.17E-06 | 6.37E-08 | 3.22E-08 | 3.13E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.17E-05** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.43** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.12 | 0.76 | 6.65 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.41** |
| $OECR_{BASE}$ | $0 | $19 | $1,157 | $58,874 | $860 | $2,408 | $0 | $0 | $19 | $0 | **$63,337** |
| $OECR_{SAMA}$ | $0 | $19 | $1,157 | $58,816 | $841 | $2,408 | $0 | $0 | $19 | $0 | **$63,260** |

This information was used in the cost-benefit calculation. The results of this calculation are provided in the following table.

**SAMA 15 Net Value**

| Unit | Base Case Cost-Risk | Revised Cost-Risk | Averted Cost-Risk |
|---|---|---|---|
| Unit 1 | $1,114,000 | $1,114,000 | $0 |
| Unit 2 | $2,980,000 | $2,960,676 | $19,324 |

The SAMA 15 results show a modest drop in the CDF and LERF metrics for Unit 2, primarily in release categories that do not involve containment failure. This is expected as, although the loss of the main feedwater and AFW systems on a loss of Train A DC power is important to decay heat removal and prevention of core damage, one train of support systems remains available for containment heat removal. There is virtually no risk benefit provided to Unit 1 upon implementation of this SAMA.

Based on a $130,000 cost of implementation for each unit, the net value for this SAMA is -$130,000 ($0 - $130,000) for Unit 1 and -$110,676 ($19,324 - $130,000) for Unit 2, which implies that this SAMA is <u>not</u> cost beneficial for either unit.

### F.6.7 SAMA 19: Upgrade RHR Suction Piping and Install Containment Isolation Valve

During plant shutdown conditions, the RHR shutdown cooling function on both units is facilitated by opening both of the two RHR pump suction MOVs in at least one of the parallel flowpaths (one from each RCS hot leg). All four of these hot leg suction isolation valves are located inside containment. A common 10" line passes through the containment, before dividing again at the suction to each RHR pump. The primary contributor to the risk of intersystem LOCA (ISLOCA) events is the catastrophic failure of the RCS hot leg-to-RHR suction MOVs during power operation, which exposes the low-pressure RHR suction piping and RHR pump seals outside containment (in the Auxiliary Building RHR pits) to RCS pressure. These events can result in large LOCAs outside containment that lead to core damage with direct containment bypass.

The RHR pump suction piping outside containment is designed for low pressure (<600 psig). RCS pressure is approximately 2235 psig during power operation. While the RHR piping likely would not rupture given exposure to RCS pressure (due to margin available in the as-built piping), the RHR pump seals are not likely to remain intact, and at least a small LOCA outside containment is the likely result. Manual valves for local isolation of the suction piping to each RHR pump are available. However, the valve handwheels are located in the RHR pits and environmental conditions in the area following rupture of the RHR pump seals are likely to prevent local operation of the valves. Also, the valves each isolate the suction to only one pump, so that both valves would have to be locally closed to stop the flow of reactor coolant out of the RHR pump seals. There is no automatic isolation valve available outside containment to prevent continuous loss of RCS inventory into the RHR pits inside the Auxiliary Building. The purpose of this SAMA is to investigate the risk benefit of upgrading the RHR suction piping and installing a normally open, automatic isolation valve in the 10" piping common to the suction of both RHR pumps outside containment.

Assumptions:

1. The SAMA 19 automatic isolation valve is assumed to be an MOV. Neither the design of this valve nor its power supply need be independent of the other hot leg suction valves, as the active and passive functions of this valve required during normal and emergency operation are opposite that required for other valves -- the active function required for this valve, to close, is only required if the other valves have failed to remain closed. For shutdown cooling operation, the valve is only required to remain open, while the other valves are required to open. For the purposes of this analysis, 480V MCC 1LA1 [2LA1] is assumed to be the power supply for the SAMA 19 MOV.

2. The signal providing automatic closure of the SAMA 19 MOV is high RHR pump suction pressure. Redundant pressure instrumentation that could be upgraded to provide this signal is available (2PT-620 and 2PT-621 [2PT-620 and 2PT-621]). As closure of this valve could impact operation of the shutdown cooling function, a 2/2 logic is assumed to be required for closure of the valve.

3. Successful automatic closure of the SAMA 19 MOV is not assumed to successfully prevent rupture of the RHR pump seals. However, this will stop the ISLOCA and allow the CVCS charging or high-head SI pumps to replace the lost RCS inventory, with decay heat removal through the steam generators. Therefore, the RHR pumps are assumed to be unavailable for recovery from the event following successful operation of the SAMA 19 MOV.

PRA Model Changes to Model SAMA:

The table below provides a listing of the new basic events included in the PRA model for this sensitivity analysis:

**SAMA 19 New Basic Events**

| Description | Probability | Comments |
|---|---|---|
| BISTABLE FOR PRESSURE CHANNEL PC-620 FAILS TO FUNCTION | 7.46E-04 | Standard bistable failure on demand probability. |
| BISTABLE FOR PRESSURE CHANNEL PC-621 FAILS TO FUNCTION | 7.46E-04 | Standard bistable failure on demand probability. |
| SAMA 19 MOV FAILS TO CLOSE | 2.94E-03 | Standard motor operated valve FTC probability. |
| PRESSURE TRANSMITTER 1PT-620 FAILS TO FUNCTION | 2.52E-05 | Standard pressure transmitter failure probability. Assumes standard 24-hour mission time. |
| PRESSURE TRANSMITTER 1PT-621 FAILS TO FUNCTION | 2.52E-05 | Standard pressure transmitter failure probability. Assumes standard 24-hour mission time. |
| SAMA 19 MOTOR OPERATED VALVE FAILS TO REMAIN OPEN | 4.80E-06 | Standard motor operated valve FTRO probability. Assumes standard 24-hour mission time. |
| SAMA 19 MOV FAILS TO REMAIN CLOSED | 4.80E-06 | Standard motor operated valve FTRC probability. Assumes standard 24-hour mission time. |
| BISTABLE FOR PRESSURE CHANNEL PC-620 FAILS TO FUNCTION | 7.46E-04 | Standard bistable failure on demand probability. |
| BISTABLE FOR PRESSURE CHANNEL PC-621 FAILS TO FUNCTION | 7.46E-04 | Standard bistable failure on demand probability. |
| SAMA 19 MOV FAILS TO CLOSE | 2.94E-03 | Standard motor operated valve FTC probability. |
| PRESSURE TRANSMITTER 2PT-620 FAILS TO FUNCTION | 2.52E-05 | Standard pressure transmitter failure probability. Assumes standard 24-hour mission time. |
| PRESSURE TRANSMITTER 2PT-621 FAILS TO FUNCTION | 2.52E-05 | Standard pressure transmitter failure probability. Assumes standard 24-hour mission time. |
| SAMA 19 MOTOR OPERATED VALVE FAILS TO REMAIN OPEN | 4.80E-06 | Standard motor operated valve FTRO probability. Assumes standard 24-hour mission time. |
| SAMA 19 MOV FAILS TO REMAIN CLOSED | 4.80E-06 | Standard motor operated valve FTRC probability. Assumes standard 24-hour mission time. |

Results of SAMA Quantification:

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table for Units 1 and 2:

| | CDF | Dose-Risk | OECR |
|---|---|---|---|
| Unit $1_{Base}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit $1_{SAMA}$ | 9.78E-06 | 2.56 | $14,612 |
| Unit 1 Percent Reduction | 0.2% | 12.6% | 7.8% |
| Unit $2_{Base}$ | 1.21E-05 | 8.43 | $63,337 |
| Unit $2_{SAMA}$ | 1.20E-05 | 8.05 | $62,115 |
| Unit 2 Percent Reduction | 0.1% | 4.5% | 1.9% |

A further breakdown of the Dose-risk and OECR information is provided below according to release category.

**SAMA 19 - Unit 1 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Frequency_{SAMA}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 1.56E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.78E-06** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | **2.56** |
| $OECR_{BASE}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |
| $OECR_{SAMA}$ | $0 | $18 | $961 | $11,709 | $741 | $1,165 | $0 | $0 | $18 | $0 | **$14,612** |

**SAMA 19 - Unit 2 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.21E-05** |
| $Frequency_{SAMA}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 1.56E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.20E-05** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.43** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | **8.05** |
| $OECR_{BASE}$ | $0 | $19 | $1,157 | $58,874 | $860 | $2,408 | $0 | $0 | $19 | $0 | **$63,337** |
| $OECR_{SAMA}$ | $0 | $19 | $1,157 | $58,895 | $860 | $1,165 | $0 | $0 | $19 | $0 | **$62,115** |

This information was used in the cost-benefit calculation. The results of this calculation are provided in the following table.

**SAMA 19 Net Value**

| Unit | Base Case Cost-Risk | Revised Cost-Risk | Averted Cost-Risk |
|---|---|---|---|
| Unit 1 | $1,114,000 | $1,053,670 | $60,330 |
| Unit 2 | $2,980,000 | $2,919,486 | $60,514 |

The results of the SAMA 19 sensitivity analysis show a relatively significant reduction in LERF risk metrics for both units. SAMA 19 provides risk benefit only to the ISLOCA release category, a component of the LERF. ISLOCA events that lead to core damage are also components of the CDF, but are small relative to the contributions from other initiating events. Although the reduction in the ISLOCA frequency is comparable between units, the percent change on Unit 1 relative to the LERF is higher, as Unit 2 LERF contains a larger component from SGTR-initiated core damage events (SGs have not yet been replaced on Unit 2 as they have on Unit 1).

Based on a $700,000 cost of implementation for each unit, the net value for this SAMA is -$639,670 ($60,330 - $700,000) for Unit 1 and -$639,486 ($60,514 - $700,000) for Unit 2, which implies that this SAMA is <u>not</u> cost beneficial for either unit.

### F.6.8 SAMA 20: Close Low Head Injection MOVs to Prevent RCS Backflow to SI System

This SAMA investigates the risk benefit of changing the normal operation position of the low head reactor vessel injection motor-operated valves (MV-32064, MV-32065 [MV-32167, MV-32168]) from open to closed. These valves function as low head SI reactor vessel isolation valves and deliver RH system flow directly to the reactor vessel from the RH pumps following a large break LOCA. Two check valves are supplied in each injection line between the MOV and the reactor vessel. The check valves function as the containment isolation valves for the low head injection lines. As these lines interface directly between the RCS and the low head RHR system, they represent potential intersystem LOCA (ISLOCA) pathways.

The current PRA results show that low head injection line check valve rupture and failure to close events are significant contributors to the overall likelihood of an ISLOCA event. As ISLOCA events are assumed to lead directly to core damage with containment bypass, operating with these valves normally closed would provide a clear benefit to prevention of an offsite release due to an ISLOCA. However, operation with these valves normally closed requires that the valves automatically open following a LOCA event to supply flow to the reactor vessel if required. Therefore, failure of these valves to open would contribute to loss of low head injection capability during LOCA events.

The low head injection MOVs were originally maintained normally closed during power operation, but were changed to normally open in the mid-1990's to eliminate concerns with pressure locking and thermal binding of the valves. An assessment of the risk benefit of this mode of operation was performed prior to the change. This pre-IPE evaluation, which focused on the change in core damage frequency (CDF), found the change in operating state for the valves to be risk-insignificant. However, the SAMA evaluation will focus on change in both CDF and LERF (large, early release frequency), and the changes in the offsite release category frequencies.

<u>Assumptions:</u>

1. It is assumed that failure of a low head injection MOV to remain closed would be alarmed in the control room. Therefore, the analysis does not assume exposure to failure during the whole operating cycle (mission time for failure to remain closed is the standard 24 hours).

2. The current double-check valve design of the low head injection lines is leak-tight such that the RHR piping upstream does not experience high pressures during

normal operation. Therefore, the analysis does not assume exposure of the low head injection MOVs (when operated normally closed) to catastrophic failure during the whole operating cycle (mission time for catastrophic failure when subjected to RCS pressure is the standard 24 hours).

PRA Model Changes to Model SAMA:

Basic events representing failures of the low head injection MOVs to open were added next to the valve "failure to remain open" basic events, wherever those events are currently located in the existing plant fault tree model. Common cause failures to open between the Train A and B MOVs on each unit were also modeled. Also, failures of the power supplies to the valves were included in the model, as the valves cannot be opened without AC power. The Train A MOVs (MV-32064 [MV-32167] are supplied with 480 V AC power from safeguards MCCs 1LA1 [2LA1] and the Train B MOVs (MV-32065 [MV-32168] are supplied from safeguards MCCs 1LA2 [2LA2]. Logic associated with loss of the train-associated S-signal was also included as failures of the valves to open.

The table below provides a listing of the new basic events included in the PRA model for this sensitivity analysis:

**SAMA 20 New Basic Events**

| Description | Probability | Comments |
|---|---|---|
| MV-32064 (LOW HEAD INJECTION TO RX VESSEL) FAILS TO OPEN | 2.88E-03 | Standard motor operated valve FTO probability. |
| MV-32064 AND MV-32065 (LOW HEAD INJECTION TO RX VESSEL) FAIL TO OPEN DUE TO CCF | 1.23E-04 | Standard motor operated valve FTO CCF probability. |
| MV-32065 (LOW HEAD INJECTION TO RX VESSEL) FAILS TO OPEN | 2.88E-03 | Standard motor operated valve FTO probability. |
| MV-32167 (LOW HEAD INJECTION TO RX VESSEL) FAILS TO OPEN | 2.88E-03 | Standard motor operated valve FTO probability. |
| MV-32167 AND MV-32168 (LOW HEAD INJECTION TO RX VESSEL) FAIL TO OPEN DUE TO CCF | 1.23E-04 | Standard motor operated valve FTO CCF probability. |
| MV-32167 (LOW HEAD INJECTION TO RX VESSEL) FAILS TO OPEN | 2.88E-03 | Standard motor operated valve FTO probability. |
| MV-32064 (LOW HEAD INJECTION TO RX VESSEL) FAILS TO REMAIN CLOSED | 4.80E-06 | Standard motor operated valve FTRC probability. Assumes standard 24-hour mission time. |
| MV-32064 (LOW HEAD INJECTION TO RX VESSEL) CATASTROPHIC LEAK | 2.40E-07 | Standard normally-closed MOV catastrophic failure probability. Assumes standard 24-hour mission time (see Assumption #2). |

**SAMA 20 New Basic Events**

| Description | Probability | Comments |
|---|---|---|
| MV-32065 (LOW HEAD INJECTION TO RX VESSEL) FAILS TO REMAIN CLOSED | 4.80E-06 | Standard motor operated valve FTRC probability. Assumes standard 24-hour mission time. |
| MV-32065 (LOW HEAD INJECTION TO RX VESSEL) CATASTROPHIC LEAK | 2.40E-07 | Standard normally-closed MOV catastrophic failure probability. Assumes standard 24-hour mission time (see Assumption #2). |
| MV-32167 (LOW HEAD INJECTION TO RX VESSEL) FAILS TO REMAIN CLOSED | 4.80E-06 | Standard motor operated valve FTRC probability. Assumes standard 24-hour mission time. |
| MV-32167 (LOW HEAD INJECTION TO RX VESSEL) CATASTROPHIC LEAK | 2.40E-07 | Standard normally-closed MOV catastrophic failure probability. Assumes standard 24-hour mission time (see Assumption #2). |
| MV-32168 (LOW HEAD INJECTION TO RX VESSEL) FAILS TO REMAIN CLOSED | 4.80E-06 | Standard motor operated valve FTRC probability. Assumes standard 24-hour mission time. |
| MV-32168 (LOW HEAD INJECTION TO RX VESSEL) CATASTROPHIC LEAK | 2.40E-07 | Standard normally-closed MOV catastrophic failure probability. Assumes standard 24-hour mission time (see Assumption #2). |

Results of SAMA Quantification:

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table for Units 1 and 2:

| | CDF | Dose-Risk | OECR |
|---|---|---|---|
| Unit $1_{Base}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit $1_{SAMA}$ | 9.78E-06 | 2.60 | $14,742 |
| Unit 1 Percent Reduction | 0.1% | 11.3% | 7.0% |
| Unit $2_{Base}$ | 1.21E-05 | 8.43 | $63,337 |
| Unit $2_{SAMA}$ | 1.20E-05 | 8.09 | $62,227 |
| Unit 2 Percent Reduction | 0.1% | 4.1% | 1.8% |

A further breakdown of the Dose-risk and OECR information is provided below according to release category.

**SAMA 20 - Unit 1 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Frequency_{SAMA}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 1.74E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.78E-06** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | **2.60** |
| $OECR_{BASE}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |
| $OECR_{SAMA}$ | $0 | $18 | $961 | $11,706 | $741 | $1,298 | $0 | $0 | $18 | $0 | **$14,742** |

**SAMA 20 - Unit 2 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.21E-05** |
| $Frequency_{SAMA}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 1.74E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.20E-05** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.43** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | **8.09** |
| $OECR_{BASE}$ | $0 | $19 | $1,157 | $58,874 | $860 | $2,408 | $0 | $0 | $19 | $0 | **$63,337** |
| $OECR_{SAMA}$ | $0 | $19 | $1,157 | $58,874 | $860 | $1,298 | $0 | $0 | $19 | $0 | **$62,227** |

This information was used in the cost-benefit calculation. The results of this calculation are provided in the following table.

**SAMA 20 Net Value**

| Unit | Base Case Cost-Risk | Revised Cost-Risk | Averted Cost-Risk |
|---|---|---|---|
| Unit 1 | $1,114,000 | $1,060,090 | $53,910 |
| Unit 2 | $2,980,000 | $2,925,354 | $54,646 |

As ISLOCA is only a very small contributor to the CDF, the primary impact of this SAMA is in the reduction of the LERF risk metric. This reduction is significant for both units (again, the percent LERF change on Unit 1 is more significant than on Unit 2 due to the higher contribution from SGTR sequences on that unit).

Based on a $313,000 cost of implementation for each unit, the net value for this SAMA is -$259,090 ($53,910 - $313,000) for Unit 1 and -$258,354 ($54,646 - $313,000) for Unit 2, which implies that this SAMA is <u>not</u> cost beneficial for either unit.

### F.6.9 SAMA 22: Provide Compressed Air Backup for Instrument Air to Containment

The risk significant function of the instrument air system supplying the containment is to support the operation of the RCS power-operated relief valves (PORVs) during bleed and feed operation for decay heat removal. On a loss of instrument air to containment, the PORVs are each supplied with air from separate backup air accumulators. These accumulators are sized for a certain number of valve operations during overpressure conditions following an accident (testing shows that the valves have capacity for 15 valve operating cycles, according to Section 5.6.1.B of Station and Instrument Air Design Basis Document, Rev. 4).

It is suspected that the air requirements during bleed and feed operations may be less than required for overpressure. However, the PRA model does not take full credit for the ability of these accumulators because their ability to supply sufficient air to support bleed and feed operation over the full range of RCS break sizes has not been verified (through testing or through engineering calculations). Bench testing of the valves for bleed and feed operation at operating pressures may not be practical. The risk benefit from this SAMA can be achieved by either:

a. Qualification of the existing accumulator air supply for bleed and feed operation, through either testing or analysis, or

b. Implementation of a plant modification that would provide a backup to the accumulators during normal plant operation to support bleed and feed operation. One possibility would be to tie into the nitrogen (or air) bottle source that supplies air to the LTOP system during outages.

<u>Assumptions:</u>

1. To estimate an upper bound on the risk benefit for this SAMA with a minimum cost, it was assumed that the PORVs accumulator air supply is successfully qualified for bleed and feed operation through analysis.

2. The upper bound on the risk benefit for this SAMA is represented in the model by setting the existing PRA failure basic events to logical FALSE.

<u>PRA Model Changes to Model SAMA:</u>

The only changes to the PRA necessary to model this SAMA were to reduce the probability of events representing failure of the PORV accumulator to provide sufficient air for bleed and feed operation. As described in Assumption #1, the PORVs accumulator air supply is assumed to be qualified for bleed and feed operation, such that the existing PRA failure basic events can be set to logical FALSE.

The table below shows the basic events that were modified to model this SAMA:

**SAMA 22 Changes to Basic Events**

| Description | Original Probability | SAMA21 Probability |
|---|---|---|
| FAILURE OF PZR PORV AIR ACCUMULATOR FOLLOWING LOSS OF AIR | 1.0E-01 | [FALSE] |
| FAILURE OF PZR PORV AIR ACCUMULATOR FOLLOWING LOSS OF AIR | 1.0E-01 | [FALSE] |

Results of SAMA Quantification:

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table for Units 1 and 2:

| | CDF | Dose-Risk | OECR |
|---|---|---|---|
| Unit $1_{Base}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit $1_{SAMA}$ | 9.75E-06 | 2.89 | $15,488 |
| Unit 1 Percent Reduction | 0.4% | 1.4% | 2.3% |
| Unit $2_{Base}$ | 1.21E-05 | 8.43 | $63,337 |
| Unit $2_{SAMA}$ | 1.18E-05 | 8.25 | $61,792 |
| Unit 2 Percent Reduction | 1.8% | 2.2% | 2.4% |

A further breakdown of the Dose-risk and OECR information is provided below according to release category.

**SAMA 22 - Unit 1 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Frequency_{SAMA}$ | 7.25E-06 | 1.92E-06 | 2.82E-07 | 2.25E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.75E-06** |
| Dose-$Risk_{BASE}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| Dose-$Risk_{SAMA}$ | 0.01 | 0.12 | 0.63 | 1.28 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.89** |
| $OECR_{BASE}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |
| $OECR_{SAMA}$ | $0 | $18 | $961 | $11,342 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,488** |

**SAMA 22 - Unit 2 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.21E-05** |
| $Frequency_{SAMA}$ | 8.33E-06 | 1.97E-06 | 3.39E-07 | 1.14E-06 | 6.45E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.18E-05** |
| Dose-$Risk_{BASE}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.43** |
| Dose-$Risk_{SAMA}$ | 0.01 | 0.12 | 0.76 | 6.49 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.25** |
| $OECR_{BASE}$ | $0 | $19 | $1,157 | $58,874 | $860 | $2,408 | $0 | $0 | $19 | $0 | **$63,337** |
| $OECR_{SAMA}$ | $0 | $19 | $1,157 | $57,337 | $852 | $2,408 | $0 | $0 | $19 | $0 | **$61,792** |

This information was used in the cost-benefit calculation. The results of this calculation are provided in the following table.

**SAMA 22 Net Value**

| Unit | Base Case Cost-Risk | Revised Cost-Risk | Averted Cost-Risk |
|---|---|---|---|
| Unit 1 | $1,114,000 | $1,098,650 | $15,350 |
| Unit 2 | $2,980,000 | $2,912,350 | $67,650 |

Similar to the SAMA 21 results, the SAMA 22 results show the primary risk benefit to be the reduction in the frequency of release category L-SR-E (pressure and temperature-induced SGTR core damage sequences). There also is a small reduction in sequences that do not lead to containment failure (primarily core damage events due to failure of secondary decay heat removal and bleed and feed failure), although these categories do not significantly impact the risk of offsite release.

Based on a $39,000 cost of implementation for each unit, the net value for this SAMA is -$23,650 ($15,350 - $39,000) for Unit 1 and $28,650 ($67,650 - $39,000) for Unit 2, which implies that this SAMA is <u>not</u> cost beneficial for Unit 1, but is cost beneficial for Unit 2.

### F.6.10 Summary

All of the SAMAs reviewed showed at least some benefit with respect to the traditional CDF and LERF risk metrics. From a cost of implementation perspective, SAMA 9 provided a positive net value for both Units 1 and 2, while SAMA 22 returned a positive net value for only Unit 2. All other SAMAs returned a negative net value. SAMAs 9 and 22 are represented by engineering analyses and procedure modifications, which are both low cost options.

SAMA 9 attempts to show through engineering analyses and procedure modifications that loss of Screenhouse Ventilation is not expected to fail operation of the safeguards vertical cooling water (CL) pumps. Computer modeling of expected room temperatures due to maximum mechanical and electrical heat loads during summer operation is anticipated to show that running electrical equipment would continue to successfully operate for a 24 hour mission time, with minimal mitigative efforts by equipment operators, e.g., opening doors, dampers, etc.

SAMA 22 is meant to qualify the capacity of the backup air accumulators for adequate operation of the PORV during bleed and feed operation in removing heat from the primary system when the steam generators are unavailable. The assumed operating conditions are based on the expected sequence of operator actions found in emergency procedures. However, costs for any required procedural changes or plant modifications resulting from the analysis were not included in the cost estimate.

## F.7 UNCERTAINTY ANALYSIS

The following three uncertainties were further investigated as to their impact on the overall SAMA evaluation:

- Use a discount rate of 7 percent, instead of 3 percent used in the base case analysis.
- Use the 95th percentile PRA results in place of the mean PRA results.
- Selected MACCS2 input variables.

### F.7.1 Real Discount Rate

A sensitivity study has been performed in order to identify how the conclusions of the SAMA analysis might change based on the value assigned to the real discount rate (RDR). The original RDR of 3 percent, which could be viewed as conservative, has been changed to 7 percent and the modified maximum averted cost-risk was re-calculated using the methodology outlined in Section F.4.

Phase I SAMAs are not impacted by use of the 7 percent RDR. The Phase I screening process involved qualitative disposition of (11) SAMAs, and hence, no PRA requantification nor implementation cost data was generated for these SAMAs. Refer to Section F.5 and Table F.5-3 for a detailed analysis of each Phase I SAMA that was screened from further analysis.

The Phase II analysis was re-performed using the 7 percent RDR. Implementation of the 7 percent RDR reduced the MMACR by 28.4 percent compared with the case where a 3 percent RDR was used. This corresponds to a decrease in the MMACR from $1,048,000 to $750,000 for Unit 1 and from 2,706,000 to 1,938,000 for Unit 2.

The Phase II SAMAs are disposition based on PRA insights or detailed analysis. All of the PRA insights used to screen the SAMAs are still applicable given the use of the 7 percent real discount rate as the change only strengthens the factors used to screen them. The SAMA candidates screened based on these insights are considered to be addressed and are not investigated any further.

The remaining Phase II SAMAs were disposition based on the results of a SAMA specific cost-benefit analysis. This step has been re-performed using the 7 percent real discount rate to calculate the net values for the SAMAs. As shown below, the determination of cost effectiveness changed for one Phase II SAMA for both units when the 7 percent RDR was used in lieu of 3 percent. Since the margin by which SAMA 9 becomes "not cost beneficial" is less than $20,000, this is considered within the noise of statistical uncertainty. This does not mean that this SAMA would be screened from consideration if a 7 percent real discount rate were applied in the SAMA analysis since other factors, such as the 95th percentile accident frequency sensitivity analysis, can also influence the decision making process.

**Unit 1 Summary of the Impact of the RDR Value on the Detailed SAMA Analyses**

| SAMA ID | Cost of Implementation | 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? |
|---|---|---|---|---|---|---|
| 1 | $4,250,000 | $268,252 | ($3,981,748) | $186,958 | ($4,063,042) | No |
| 2 | $300,000 | $123,376 | ($176,624) | $87,054 | ($212,946) | No |
| 3 | $250,000 | $74,956 | ($175,044) | $53,680 | ($196,320) | No |
| 5 | $1,500,000 | $75,942 | ($1,424,058) | $51,184 | ($1,448,816) | No |
| 9 | $62,500 | $62,746 | $246 | $44,670 | ($17,830) | Yes |
| 10 | $2,866,000 | $46,870 | ($2,819,130) | $34,054 | ($2,831,946) | No |
| 12 | $900,000 | $186,188 | ($713,812) | $131,094 | ($768,906) | No |
| 15 | $130,000 | $0 | ($130,000) | $0 | ($130,000) | No |
| 17 | $2,362,000 | $88,030 | ($2,273,970) | $56,160 | ($2,305,840) | No |
| 19 | $700,000 | $60,330 | ($639,670) | $39,456 | ($660,544) | No |
| 19a | $1,935,000 | $329,802 | ($1,605,198) | $222,090 | ($1,712,910) | No |
| 20 | $313,000 | $53,910 | ($259,090) | $35,312 | ($277,688) | No |
| 21 | $3,000,000 | $11,286 | ($2,988,714) | $7,480 | ($2,992,520) | No |
| 22 | $39,000 | $15,350 | ($23,650) | $9,894 | ($29,106) | No |

**Unit 2 Summary of the Impact of the RDR Value on the Detailed SAMA Analyses**

| SAMA ID | Cost of Implementation | 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? |
|---|---|---|---|---|---|---|
| 1 | $4,250,000 | $270,474 | ($3,979,526) | $188,620 | ($4,061,380) | No |
| 2 | $300,000 | $123,092 | ($176,908) | $86,958 | ($213,042) | No |
| 3 | $250,000 | $76,654 | ($173,346) | $54,550 | ($195,450) | No |
| 5 | $1,500,000 | $222,610 | ($1,277,390) | $144,138 | ($1,355,862) | No |
| 9 | $62,500 | $62,918 | $418 | $44,020 | ($18,480) | Yes |
| 10 | $2,866,000 | $48,630 | ($2,817,370) | $34,154 | ($2,831,846) | No |
| 12 | $900,000 | $302,132 | ($597,868) | $204,688 | ($695,312) | No |
| 15 | $130,000 | $19,324 | ($110,676) | $13,352 | ($116,648) | No |
| 17 | $2,362,000 | $488,118 | ($1,873,882) | $309,512 | ($2,052,488) | No |
| 19 | $700,000 | $60,514 | ($639,486) | $39,352 | ($660,648) | No |
| 19a | $1,935,000 | $929,586 | ($1,005,414) | $601,740 | ($1,333,260) | No |
| 20 | $313,000 | $54,646 | ($258,354) | $35,516 | ($277,484) | No |
| 21 | $3,000,000 | $12,518 | ($2,987,482) | $8,426 | ($2,991,574) | No |
| 22 | $39,000 | $67,650 | $28,650 | $43,452 | $4,452 | 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 (i.e., failure probabilities associated with plant equipment and operator actions). If the best estimate failure probability values were lower than the "actual" failure probabilities, the PRA model could underestimate plant risk and yield lower than "actual" averted cost-risk values for potential SAMAs. Therefore, using the high end of the failure probability distribution is a means of assessing the possible effect of best-estimate failure probabilities being too low.

A Level 1 internal events model uncertainty analysis was performed for PINGP Units 1 and 2. Most plants incorporate only Level 1 analyses in their SAMA reports. The reason Level 2 analyses are not typically used is due to the differing degree of development and uncertainties between the two models. Specifically, the Level 1 model tends to represent the plant in a more thorough and comprehensive manner as opposed to the Level 2 model. Furthermore, there are more release contributors beyond those captured by LERF. As such, for the purposes of the 95th percentile analysis, only Level 1 results are used in the uncertainty process. The results of the Level 1 calculation are provided below:

In performing the sensitivity analysis, each of the SAMA PRA model changes (the Phase I and II SAMAs identified in Table F.5-3) were used in determining the appropriate value for the 95th percentile since different events and failure frequencies may be more important when comparing one model change with another. 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. The analysis was run using the EPRI R&R Workstation UNCERT code (version 2.3a) using 25,000 trials for each simulation:

The results of these calculations are provided in the below tables. The term $CDF_{pe}$ refers to the CDF point estimate for each unit, i.e., 9.79E-06 for Unit 1 and 1.21E-5 for Unit 2.

### Summary of Unit 1 Uncertainty Distribution

| Unit 1 SAMA | Mean | 5% | 50% | 95% | Factor > $CDF_{pe}$ | Std Dev |
|---|---|---|---|---|---|---|
| 1 | 6.35E-06 | 1.87E-06 | 4.38E-06 | 1.56E-05 | 1.6 | 1.50E-05 |
| 2 | 8.20E-06 | 1.88E-06 | 4.60E-06 | 2.08E-05 | 2.1 | 3.50E-05 |
| 3 | 9.05E-06 | 2.26E-06 | 5.42E-06 | 2.34E-05 | 2.4 | 1.89E-05 |
| 5 | 1.07E-05 | 2.55E-06 | 6.42E-06 | 2.79E-05 | 2.8 | 2.91E-05 |
| 9 | 9.52E-06 | 2.28E-06 | 5.62E-06 | 2.51E-05 | 2.6 | 2.49E-05 |
| 10 | 9.76E-06 | 2.23E-06 | 5.64E-06 | 2.54E-05 | 2.6 | 2.76E-05 |
| 12 | 7.14E-06 | 1.38E-06 | 3.68E-06 | 1.91E-05 | 2.0 | 2.77E-05 |
| 15 | 1.08E-05 | 2.55E-06 | 6.41E-06 | 2.84E-05 | 2.9 | 3.89E-05 |
| 17 | 1.08E-05 | 2.54E-06 | 6.36E-06 | 2.80E-05 | 2.9 | 2.70E-05 |
| 19 | 1.08E-05 | 2.54E-06 | 6.35E-06 | 2.80E-05 | 2.9 | 4.44E-05 |
| 19a | 7.30E-06 | 2.15E-06 | 5.05E-06 | 1.79E-05 | 1.8 | 1.23E-05 |
| 20 | 1.06E-05 | 2.54E-06 | 6.40E-06 | 2.79E-05 | 2.8 | 2.62E-05 |
| 21 | 1.08E-05 | 2.51E-06 | 6.35E-06 | 2.83E-05 | 2.9 | 2.89E-05 |
| 22 | 1.07E-05 | 2.54E-06 | 6.33E-06 | 2.82E-05 | 2.9 | 3.33E-05 |

### Summary of Unit 2 Uncertainty Distribution

| Unit 2 SAMA | Mean | 5% | 50% | 95% | Factor > $CDF_{pe}$ | Std Dev |
|---|---|---|---|---|---|---|
| 1 | 8.62E-06 | 2.54E-06 | 6.02E-06 | 2.15E-05 | 1.8 | 1.11E-05 |
| 2 | 1.06E-05 | 2.58E-06 | 6.25E-06 | 2.79E-05 | 2.3 | 2.94E-05 |
| 3 | 1.15E-05 | 2.96E-06 | 7.17E-06 | 2.92E-05 | 2.4 | 2.75E-05 |
| 5 | 1.33E-05 | 3.25E-06 | 8.06E-06 | 3.45E-05 | 2.9 | 3.40E-05 |
| 9 | 1.21E-05 | 3.03E-06 | 7.33E-06 | 3.03E-05 | 2.5 | 4.37E-05 |
| 10 | 1.22E-05 | 2.93E-06 | 7.37E-06 | 3.20E-05 | 2.7 | 2.55E-05 |
| 12 | 9.51E-06 | 2.00E-06 | 5.34E-06 | 2.63E-05 | 2.2 | 2.84E-05 |
| 15 | 1.28E-05 | 3.17E-06 | 7.83E-06 | 3.33E-05 | 2.8 | 2.98E-05 |
| 17 | 1.29E-05 | 3.26E-06 | 7.95E-06 | 3.34E-05 | 2.8 | 4.65E-05 |
| 19 | 1.32E-05 | 3.33E-06 | 8.19E-06 | 3.46E-05 | 2.9 | 2.95E-05 |
| 19a | 9.37E-06 | 2.79E-06 | 6.56E-06 | 2.29E-05 | 1.9 | 1.62E-05 |
| 20 | 1.32E-05 | 3.34E-06 | 8.15E-06 | 3.43E-05 | 2.8 | 3.68E-05 |
| 21 | 1.31E-05 | 3.26E-06 | 8.08E-06 | 3.31E-05 | 2.7 | 4.28E-05 |
| 22 | 1.26E-05 | 3.18E-06 | 7.93E-06 | 3.36E-05 | 2.8 | 2.33E-05 |

In general, the above tables reveal an average factor of about 2.5 greater than the respective point estimate CDF for each unit, which is in agreement with industry experience. Using the factors for each individual SAMA are determined to represent a more realistic and case-specific value than that obtained when applying one overall estimate for the 95$^{th}$ percentile. Therefore, for this analysis, the 95$^{th}$ percentile for each SAMA is used to examine Phase I and II impacts.

## F.7.2.1 Phase I Impact

For the impacts on Phase I screening, use of the 95th percentile PRA results will increase the MACR and may reveal potential cost benefits due to implementing some of the high cost SAMAs originally screened in Table F.5-3. Therefore, five of the SAMAs (1, 10, 17, 19a, and 21) that were not evaluated in Phase II are presented here, following the same methodology and process as was used in Section F.6. The results of these SAMA evaluations are then used in Section F.7.2.3 to quantitatively determine any potential cost or risk benefits. However, due to their high implementation costs, the benefit gleaned from the implementation of these SAMAs must be extremely large in order to be cost beneficial.

### F.7.2.1.1 SAMA 1: Recirculation Automatic Swap to Containment Sump

Following the injection phase of a LOCA, the Refueling Water Storage Tank (RWST) is emptied and the suction supply to the high and low head ECCS systems must be transferred to the containment sump. The transfer currently relies on operator action, including some local, manual actions. These operator actions are among the most risk-significant human actions modeled in the PRA. This SAMA investigates the risk benefit of installing control logic to automatically swap to recirculation mode of ECCS, drawing suction from containment sump prior to depletion of RWST. (Locally operators need to vent valve bonnets on Sump B to RHR MVs to prevent hydraulic lock. Also improper action by not closing RWST to RHR MVs first can potentially drain RWST back to Sump B).

Assumptions:

1. For the purposes of this SAMA, it was assumed that all of the existing ECCS equipment (piping, valves, breakers, pumps, etc.) that must actively change state to affect the transfer to recirculation still exists following implementation of the automatic switchover modification. The only difference is that the operator action required to initiate the transfer has been replaced by an automatic signal. Therefore, the failure rates of valves to open, pumps to start, etc. are not changed from the original Level 2 PRA analysis.

2. It is assumed that the automatic logic function producing the transfer-to-recirculation actuation signal is designed such that it is highly reliable. Although the final implementation is not likely to produce a system with a negligible failure rate, a “near zero” failure rate may be assumed for the purposes of this calculation (determination of the maximum risk benefit for the SAMA implementation).

PRA Model Changes to Model SAMA:

All operator actions associated with transfer to recirculation were set to logical FALSE to model the maximum risk benefit that could be obtained with this plant modification. The basic event changes are shown in the table below:

**SAMA 1 Basic Event Changes**

| Original Probability | Sensitivity Probability (1) | Description |
|---|---|---|
| 5.30E-02 | FALSE | OPERATOR FAIL TO INITIATE HIGH HEAD RECIRC COND. ON EOPHXCONXY |
| 5.30E-02 | FALSE | OPERATOR FAILS TO INITIATE HH RECIRC COND. ON FAILURE OF RCS COOLDOWN AND DEPRESSURIZATION. |
| 1.50E-01 | FALSE | OPERATOR FAILS TO INITIATE HH RECIRC FOR SLOCA COND. ON FAILURE OF RCS COOLDOWN AND DEPRESSURIZATION. |
| 3.60E-03 | FALSE | OPERATOR FAILS TO INITIATE HIGH HEAD RECIRC. FOR A SMALL LOCA |
| 9.50E-03 | FALSE | OPERATOR FAILS TO INITATE HIGH HEAD RECIRC. FOR A MEDIUM LOCA |
| 6.80E-02 | FALSE | OPERATOR FAILS TO INITIATE LOW HEAD RECIRC. WHEN REQUIRED |

(1) Basic Event set to logical FALSE to obtain maximum risk benefit for sensitivity case

Results of SAMA Quantification:

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table for Units 1 and 2:

| | CDF | Dose-Risk | OECR |
|---|---|---|---|
| Unit $1_{Base}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit $1_{SAMA}$ | 5.40E-06 | 2.72 | $14,225 |
| Unit 1 Percent Reduction | 44.9% | 7.2% | 10.3% |
| Unit $2_{Base}$ | 1.21E-05 | 8.43 | $63,337 |
| Unit $2_{SAMA}$ | 7.62E-06 | 8.22 | $61,702 |
| Unit 2 Percent Reduction | 36.8% | 2.5% | 2.6% |

A further breakdown of the Dose-risk and OECR information is provided below according to release category.

**SAMA 1 - Unit 1 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Frequency_{SAMA}$ | 2.90E-06 | 1.92E-06 | 2.82E-07 | 2.09E-07 | 2.33E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 1.23E-10 | 2.32E-11 | **5.40E-06** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| $Dose\text{-}Risk_{SAMA}$ | 0.00 | 0.12 | 0.63 | 1.19 | 0.05 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.72** |
| $OECR_{BASE}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |
| $OECR_{SAMA}$ | $0 | $18 | $961 | $10,527 | $308 | $2,408 | $0 | $0 | $3 | $0 | **$14,225** |

**SAMA 1 - Unit 2 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.21E-05** |
| $Frequency_{SAMA}$ | 4.10E-06 | 1.97E-06 | 3.39E-07 | 1.15E-06 | 3.22E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 2.00E-10 | 2.32E-11 | **7.62E-06** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.43** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.12 | 0.76 | 6.53 | 0.07 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.22** |
| $OECR_{BASE}$ | $0 | $16 | $1,007 | $50,425 | $669 | $2,034 | $0 | $0 | $16 | $0 | **$63,337** |
| $OECR_{SAMA}$ | $0 | $19 | $1,157 | $57,689 | $425 | $2,408 | $0 | $0 | $4 | $0 | **$61,702** |

This information was used in the cost-benefit calculation. The results of this calculation are provided in the following table.

**SAMA 1 Net Value**

| Unit | Base Case Cost-Risk | Revised Cost-Risk | Averted Cost-Risk |
|---|---|---|---|
| Unit 1 | $1,114,000 | $845,748 | $268,252 |
| Unit 2 | $2,980,000 | $2,709,526 | $270,474 |

The results of the SAMA 1 quantification show a large reduction in the CDF risk metrics for both units, and a corresponding decrease in the frequencies of a number of release categories. The release categories that showed the largest decrease in frequency relative to CDF were in those categories in which containment remained intact (category H-XX-X is considered to be bounding among these and represents all of the risk reduction from containment intact categories in the table above).

Based on a $4,250,000 cost of implementation for each unit, the net value for this SAMA is -3,981,748 ($268,252 - $4,250,000) for Unit 1 and -$3,979,526 ($270,474 - $4,250,000) for Unit 2, which implies that this SAMA is <u>not</u> cost beneficial for both Units 1 and 2.

#### F.7.2.1.2 <u>SAMA 10: Alternate Means of Charging Pump Suction Transfer (VCT to RWST)</u>

The purpose of this SAMA is to investigate the risk benefit of improving the reliability of the automatic transfer of charging pump suction (from the VCT to the RWST on low VCT level). Specifically, this SAMA investigates installation of a third level transmitter and instrumentation channel, and logic change (from 2/2 to 2/3) for initiation of the automatic transfer.

Although level channel 1LT-112 [2LT-112] also supports automatic VCT makeup control, which is modeled in the PRA, no similar function was assumed for the new SAMA 10 level channel as this is not a risk significant function of the VCT level instrumentation.

PRA Model Changes to Model SAMA:

The table below provides a listing of the new basic events included in the PRA model for this sensitivity analysis:

**SAMA 10 New Basic Events**

| Description | Probability | Comments |
|---|---|---|
| BISTABLE SAMA 10 FAILS TO FUNCTION | 7.46E-04 | Standard bistable failure probability. |
| VC: LEVEL TRANSMITTER FAILS TO FUNCTION (SAMA 10) | 1.90E-04 | Standard level transmitter failure probability. Assumes standard 24-hour mission time. |
| VC: TWO LEVEL TRANSMITTERS FAIL DUE TO CCF (SAMA 10 AND 1LT-112) | 8.04E-06 | Standard level transmitter CCF probability. Assumes standard 24-hour mission time. |
| VC: TWO LEVEL TRANSMITTERS FAIL DUE TO CCF (SAMA 10 AND 1LT-141) | 8.04E-06 | Standard level transmitter CCF probability. Assumes standard 24-hour mission time. |
| BISTABLE SAMA 10 FAILS TO FUNCTION | 7.46E-04 | Standard bistable failure probability. |
| VC: LEVEL TRANSMITTER FAILS TO FUNCTION (SAMA10) | 1.90E-04 | Standard level transmitter failure probability. Assumes standard 24-hour mission time. |
| VC: TWO LEVEL TRANSMITTERS FAIL DUE TO CCF (SAMA 10 AND 2LT-112) | 8.04E-06 | Standard level transmitter CCF probability. Assumes standard 24-hour mission time. |
| VC: TWO LEVEL TRANSMITTERS FAIL DUE TO CCF (SAMA 10 AND 2LT-141) | 8.04E-06 | Standard level transmitter CCF probability. Assumes standard 24-hour mission time. |

Results of SAMA Quantification:

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table for Units 1 and 2:

| | CDF | Dose-Risk | OECR |
|---|---|---|---|
| Unit $1_{Base}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit $1_{SAMA}$ | 8.95E-06 | 2.88 | $15,711 |
| Unit 1 Percent Reduction | 8.6% | 1.7% | 0.9% |
| Unit $2_{Base}$ | 1.21E-05 | 8.43 | $63,337 |
| Unit $2_{SAMA}$ | 1.12E-05 | 8.36 | $63,197 |
| Unit 2 Percent Reduction | 7.1% | 0.9% | 0.2% |

A further breakdown of the Dose-risk and OECR information is provided below according to release category.

**SAMA 10 - Unit 1 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Frequency_{SAMA}$ | 7.10E-06 | 1.27E-06 | 2.82E-07 | 2.31E-07 | 5.19E-08 | 3.22E-08 | 2.10E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **8.95E-06** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.08 | 0.63 | 1.32 | 0.11 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.88** |
| $OECR_{BASE}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |
| $OECR_{SAMA}$ | $0 | $12 | $961 | $11,628 | $684 | $2,408 | $0 | $0 | $18 | $0 | **$15,711** |

**SAMA 10 - Unit 2 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.21E-05** |
| $Frequency_{SAMA}$ | 8.34E-06 | 1.30E-06 | 3.39E-07 | 1.17E-06 | 6.09E-08 | 3.22E-08 | 2.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.12E-05** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.43** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.08 | 0.76 | 6.65 | 0.13 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.36** |
| $OECR_{BASE}$ | $0 | $19 | $1,157 | $58,874 | $860 | $2,408 | $0 | $0 | $19 | $0 | **$63,337** |
| $OECR_{SAMA}$ | $0 | $13 | $1,157 | $58,796 | $804 | $2,408 | $0 | $0 | $19 | $0 | **$63,197** |

This information was used in the cost-benefit calculation. The results of this calculation are provided in the following table.

**SAMA 10 Net Value**

| Unit | Base Case Cost-Risk | Revised Cost-Risk | Averted Cost-Risk |
|---|---|---|---|
| Unit 1 | $1,114,000 | $1,067,130 | $46,870 |
| Unit 2 | $2,980,000 | $2,931,370 | $48,630 |

The SAMA 10 results are similar to the SAMA 3 results, as the concern addressed with this alternative is shared by both SAMAs (charging pump suction supply). Both SAMAs reduce the CDF primarily by reducing the potential for RCP seal LOCAs due to failures of the suction switchover from the VCT to the RWST on low VCT level. The magnitude of the SAMA 10 benefits are generally lower than the SAMA 3 benefits simply because the likelihood of level transmitter failure is lower than the likelihood of MOV failure.

Based on a $2,866,000 cost of implementation for each unit, the net value for this SAMA is -$2,819,130 ($46,870 - $2,866,000) for Unit 1 and -$2,817,370 ($48,630 - $2,866,000) for Unit 2, which implies that this SAMA is <u>not</u> cost beneficial for either unit.

F.7.2.1.3 SAMA 17: Bypass Around RHR Loop B Return Valves

The RHR to RCS Loop B return valve (MV-32066 [MV-32169]) is important to plant risk in two ways:

1. As a normally-closed, motor-operated valve located in the low pressure RHR return piping to the RCS, it represents a single failure point for shutdown cooling (SDC).

2. As a containment isolation valve for a system that interfaces with the RCS during power operation, its failure to remain closed (or catastrophic rupture) contributes to the potential for an ISLOCA.

The purpose of this SAMA is to investigate the risk benefit of including a bypass line with an isolation valve around the RHR Loop B return valve. The intent of this modification would be to reduce the risk associated with failure of the return valve to open.

Assumptions:

1. The modification design is assumed to prevent a significant increase in the potential for ISLOCA. For the purposes of this analysis, it is assumed that multiple normally-closed isolation valves are included in the bypass line (i.e., the primary, power-operated isolation valve, and a check valve). This would provide 3 valves for isolating the RCS from ISLOCA through the bypass line (SI-6-2 [2SI-6-2], the SAMA 17 bypass isolation power-operated valve, and the SAMA 17 bypass isolation check valve).

2. The RCS pressure interlock preventing inadvertent operation of the existing RHR Loop B isolation MOV are assumed to also apply to the SAMA 17 bypass MOV. However, the pressure transmitters providing signals for the interlock are assumed to operate from the opposite train (SAMA 17 MOV uses 1PT-419 [2PT-419] instead of 1PT-420 [2PT-420]). The potential for common cause failure of the pressure transmitters is included in the SAMA 17 MOV failure modeling.

3. The SAMA 17 power-operated isolation valve is assumed to be a motor-operated valve, using an opposite-train power supply than that used by MV-32066 [MV-32169]. In addition, the valve and its motor operator are assumed to be of a different make than MV-32066 [MV-32169] in order to minimize the risk contribution from common-cause failures. Use of an MOV instead of an AOV eliminates the dependence on instrument air inside containment (the reliability of the containment air supply is already a significant contributor to risk).

4. The SAMA 17 MOV is assumed to be powered from an AC source of the opposite train than that used by MV-32066 [MV-32169]. For the purposes of this analysis, the 480V MCC assumed to power the SAMA 17 MOV is 1LA2 [2LA2].

5. The SAMA 17 isolation check valve is assumed to be of a different make and design than the other RHR and SI injection check valves in order to minimize the risk contribution from common-cause failures.

<u>PRA Model Changes to Model SAMA:</u>

The table below provides a listing of the new basic events included in the PRA model for this sensitivity analysis:

**SAMA 17 New Basic Events**

| Description | Probability | Comments |
|---|---|---|
| SAMA 17 MOTOR OPERATED VALVE FAILS TO OPEN | 3.00E-03 | Standard motor operated valve FTO probability. |
| SAMA 17 MOTOR OPERATED VALVE FAILS TO REMAIN OPEN | 4.80E-06 | Standard motor operated valve FTRO probability. Assumes standard 24-hour mission time. |
| SAMA 17 CHECK VALVE FAILS TO OPEN | 5.00E-05 | Standard check valve FTO probability. |
| SAMA 17 MOTOR OPERATED VALVE FAILS TO OPEN | 3.00E-03 | Standard motor operated valve FTO probability. |
| SAMA 17 MOTOR OPERATED VALVE FAILS TO REMAIN OPEN | 4.80E-06 | Standard motor operated valve FTRO probability. Assumes standard 24-hour mission time. |
| SAMA 17 CHECK VALVE FAILS TO OPEN | 5.00E-05 | Standard check valve FTO probability. |

<u>Results of SAMA Quantification:</u>

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table for Units 1 and 2:

| | CDF | Dose-Risk | OECR |
|---|---|---|---|
| Unit $1_{Base}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit $1_{SAMA}$ | 9.69E-06 | 2.68 | $13,592 |
| Unit 1 Percent Reduction | 1.1% | 8.5% | 14.3% |
| Unit $2_{Base}$ | 1.21E-05 | 8.43 | $63,337 |
| Unit $2_{SAMA}$ | 1.17E-05 | 6.98 | $50,616 |
| Unit 2 Percent Reduction | 3.2% | 17.2% | 20.1% |

A further breakdown of the Dose-risk and OECR information is provided below according to release category.

**SAMA 17 - Unit 1 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Frequency_{SAMA}$ | 7.22E-06 | 1.92E-06 | 2.82E-07 | 1.88E-07 | 5.59E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.69E-06** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.12 | 0.63 | 1.07 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.68** |
| $OECR_{BASE}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |
| $OECR_{SAMA}$ | $0 | $18 | $961 | $9,450 | $737 | $2,408 | $0 | $0 | $18 | $0 | **$13,592** |

**SAMA 17 - Unit 2 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.21E-05** |
| $Frequency_{SAMA}$ | 8.39E-06 | 1.97E-06 | 3.39E-07 | 9.18E-07 | 6.45E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.17E-05** |
| $\text{Dose-Risk}_{BASE}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.43** |
| $\text{Dose-Risk}_{SAMA}$ | 0.01 | 0.12 | 0.76 | 5.22 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **6.98** |
| $OECR_{BASE}$ | $0 | $19 | $1,157 | $58,874 | $860 | $2,408 | $0 | $0 | $19 | $0 | **$63,337** |
| $OECR_{SAMA}$ | $0 | $19 | $1,157 | $46,162 | $851 | $2,408 | $0 | $0 | $19 | $0 | **$50,616** |

This information was used in the cost-benefit calculation. The results of this calculation are provided in the following table.

**SAMA 17 Net Value**

| Unit | Base Case Cost-Risk | Revised Cost-Risk | Averted Cost-Risk |
|---|---|---|---|
| Unit 1 | $1,114,000 | $1,025,970 | $88,030 |
| Unit 2 | $2,980,000 | $2,491,882 | $488,118 |

SAMA 17 provides a relatively slight reduction in the CDF values for Unit 1 and Unit 2 primarily due to the increased reliability of SDC on events involving small LOCAs and SGTR with successful high head injection. As the sequences which benefit from the SAMA 17 modification are those in which the SDC containment isolation MOV fails to open, the low-head RHR system and its support systems are likely to be available to support containment heat removal. The most significant benefit provided by this SAMA is to reduce the frequency of late core damage from SGTR events (accident class/release category GLH). The PRA model assumes that SDC must be functional for long term recovery from SGTR events involving operator failure to reduce RCS pressure to below SG pressure prior to SG overfill. Note that, as with SAMA 12, the beneficial impact of this SAMA is even greater for Unit 2, which has a higher potential for SGTR events (SGs have not been replaced on Unit 2 as they have on Unit 1).

Based on a $2,362,000 cost of implementation for each unit, the net value for this SAMA is -$2,273,970 ($88,030 - $2,362,000) for Unit 1 and -$1,873,882 ($488,118 - $2,362,000) for Unit 2, which implies that this SAMA is <u>not</u> cost beneficial for either unit.

#### F.7.2.1.4 <u>SAMA 19a: Replenish RWST from Large Water Source</u>

The RWST is the initial suction supply for the high and low pressure ECCS subsystems (SI and RHR pumps, respectively). When the RWST has been depleted following the injection phase of a loss of coolant accident, the ECCS trains are realigned for recirculation operation with suction taken from the containment sump. This realignment requires successful manual (and some local) operator actions. The time available to the operators to perform these actions varies from a few minutes to hours depending upon the size of the primary system break flow. Therefore, for LOCA accident sequences, it is clear that there would be some risk benefit for implementation of a plant change that would allow the time available for operator action to be extended.

For accidents which involve LOCAs outside containment however (i.e., steam generator tube rupture events, or intersystem LOCAs), recirculation is not an option. Intersystem LOCAs are risk significant for offsite releases, but typically the ECCS subsystem components cannot be expected to remain operable in these events for any significant length of time following the initiator (due to harsh environmental conditions produced in the Auxiliary Building). For SGTR events however, the ECCS subsystems (including the high pressure SI system) remain available and will inject the contents of the RWST into the RCS. In these events, quick operator action is required to cool down and depressurize the RCS to stop the leakage into the steam generator. If this action fails, then a period of hours is available to complete cooldown and depressurization and to initiate long term decay heat removal with RHR shutdown cooling before the RWST is completely emptied. Therefore, during a SGTR event, it would be beneficial to have the ability to replenish the RWST in order to give the operators more time to perform the required actions for initiation of long term decay heat removal.

This SAMA investigates the risk benefit of providing a reliable backup large water source for replenishing the RWST following an accident. Sources available onsite that could be connected (either through existing connections and piping or via a plant modification) include the Spent Fuel Pool (SFP), the opposite unit RWST, CVCS monitor tanks, CVCS holdup tanks, and CVCS boric acid storage tanks (BASTs). Each of these sources would likely require a pump (i.e., SFP pump, RWST purification pump, CVCS monitor tank pump, etc.) to ensure that the inventory is successfully transferred to the RWST on the affected unit.

For the purposes of this analysis, the opposite unit RWST is chosen as the alternate source, as it is already designed as a supply for ECCS injection. Piping a pump to assist in the water transfer operation, and procedural guidance to allow transfer of one RWST to another are currently available (see procedure C16, Rev. 46). However, the existing equipment and procedure are not designed for post-accident operations and will likely need to be upgraded to support this SAMA.

<u>Assumptions:</u>

1. For the purposes of this analysis, it is assumed that modifications to the plant are made such that the RWST refill is highly likely to be successful, including pump(s), piping and valves necessary to perform the transfer.

2. For the purposes of this analysis, it is assumed that the RWST refill is accomplished using operator action that can be performed from the control room using proceduralized actions to start a pump and operate two power-operated valves (both valves must operate for success; one must open and the other must close).

3. For the purposes of this analysis, it is assumed that the benefit for RWST refill is limited to an enhanced probability of operator success in transferring to high head recirculation and in cooling down and depressurizing the RCS and initiating shutdown cooling for SGTR events. Other benefits (such as increased time for repair of failed equipment, etc.) are not credited in this analysis.

4. Due to the short time available and requirement for other local operator actions performed at the same time, a minimum amount of credit for RWST refill is taken for Medium LOCA and Large LOCA scenarios (50% reduction in transfer to recirculation failure probability). Due to the significantly longer time available, it is assumed that a larger amount of credit can be applied to all other scenarios requiring ECCS injection (order of magnitude reduction in failure probabilities for transfer to high head recirculation and SGTR RCS cooldown, etc. operator actions).

5. The pump and valves required to actively function to support the RWST refill operation are assumed to be motor-operated, with power from a safeguards electrical source (MCC 1T1, the AC source for 121 SFP pump).

6. The potential that the SAMA19a operator action may be conditional upon the transfer to recirculation or SGTR recovery actions was not investigated in detail for this analysis. As SAMA19a involves an operator action performed from the control room, which is applied to sequences involving failure of other operator actions that are at least partially performed from the control room, there are issues of dependency between the failure rates of these actions. Preliminary quantification runs for this SAMA indicate that it provides very little benefit if no credit is given for sequences involving other dependent operator actions, as these failures are the dominant means of failing the transfer function. For the purposes of this SAMA, it is assumed that the issue of HRA dependency is resolved in the design and implementation of SAMA19a to the extent that all dependence can be covered by multiplying the standard 5E-2 HRA screening value by a factor of 2 (HRA applied = 1E-1).

7. Credit for improvement of the manual transfer to containment spray recirculation (CSR) was not given for this SAMA. Previous analyses have shown that failure of CSR is not a large risk contributor to the PINGP Level 2 results.

PRA Model Changes to Model SAMA:

The table below provides a listing of the new basic events included in the PRA model for this sensitivity analysis:

**SAMA 19a New Basic Events**

| Description | Probability | Comments |
|---|---|---|
| OPERATOR FAILS TO PERFORM SAMA19a (REFILL RWST) WHEN REQUIRED | 1.00E-01 | Standard HRA screening value, multiplied by 2 (to account for dependency; all actions assumed to be performed from CRM) |
| SAMA19a MOTOR OPERATED VALVE #1 FAILS TO OPEN | 3.00E-03 | Standard motor operated valve FTO probability. |
| SAMA19a MOV #1 FAILS TO REMAIN OPEN | 4.80E-06 | Standard motor operated valve FTRO probability. Assumes standard 24-hour mission time. |
| SAMA19a MOTOR OPERATED VALVE #2 FAILS TO CLOSE | 2.94E-03 | Standard motor operated valve FTC probability. |
| SAMA19a MOV #1 FAILS TO REMAIN CLOSED | 4.80E-06 | Standard motor operated valve FTRC probability. Assumes standard 24-hour mission time. |
| SAMA19a OPERATOR ACTION SUCCESS CREDIT (OTHER THAN LG/MED LOCA) | 1.00E-01 | See Assumption #4. |
| SAMA19a SUCCESS CREDIT FOR HI HEAD RECIRC TRANSFER (LG./MED. LOCAs) | 5.00E-01 | See Assumption #4. |

Results of SAMA Quantification:

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table for Units 1 and 2:

| | CDF | Dose-Risk | OECR |
|---|---|---|---|
| Unit $1_{Base}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit $1_{SAMA}$ | 6.46E-06 | 2.39 | $11,184 |
| Unit 1 Percent Reduction | 34.1% | 18.4% | 29.4% |
| Unit $2_{Base}$ | 1.21E-05 | 8.43 | $63,337 |
| Unit $2_{SAMA}$ | 8.37E-06 | 6.09 | $42,874 |
| Unit 2 Percent Reduction | 30.6% | 27.8% | 32.3% |

A further breakdown of the Dose-risk and OECR information is provided below according to release category.

**SAMA 19a - Unit 1 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Frequency_{SAMA}$ | 4.02E-06 | 1.92E-06 | 2.82E-07 | 1.46E-07 | 3.33E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 1.23E-10 | 2.32E-11 | **6.46E-06** |
| Dose-$Risk_{BASE}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| Dose-$Risk_{SAMA}$ | 0.01 | 0.12 | 0.63 | 0.83 | 0.07 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.39** |
| $OECR_{BASE}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |
| $OECR_{SAMA}$ | $0 | $18 | $961 | $7,355 | $439 | $2,408 | $0 | $0 | $3 | $0 | **$11,184** |

**SAMA 19a - Unit 2 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.21E-05** |
| $Frequency_{SAMA}$ | 5.23E-06 | 1.97E-06 | 3.39E-07 | 7.70E-07 | 4.22E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 2.00E-10 | 2.32E-11 | **8.37E-06** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.43** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.12 | 0.76 | 4.38 | 0.09 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **6.09** |
| $OECR_{BASE}$ | $0 | $19 | $1,157 | $58,874 | $860 | $2,408 | $0 | $0 | $19 | $0 | **$63,337** |
| $OECR_{SAMA}$ | $0 | $19 | $1,157 | $38,729 | $557 | $2,408 | $0 | $0 | $4 | $0 | **$42,874** |

This information was used in the cost-benefit calculation. The results of this calculation are provided in the following table.

**SAMA 19a Net Value**

| Unit | Base Case Cost-Risk | Revised Cost-Risk | Averted Cost-Risk |
|---|---|---|---|
| Unit 1 | $1,114,000 | $784,198 | $329,802 |
| Unit 2 | $2,980,000 | $2,050,414 | $929,586 |

The results of the SAMA 19a sensitivity analysis show a large drop in both the CDF and LERF risk metrics for both units. This CDF reduction is primarily due to the high importance of the transfer to recirculation operator action in preventing core damage following a LOCA. The LERF reduction is due to a significant reduction in the frequency of L-SR-E release category sequences as failure of the recirculation transfer leads to core damage at high pressure. The percent LERF change on Unit 1 is more significant than on Unit 2 due to the higher contribution from SGTR sequences on Unit 2 (SGs have not been replaced on that unit).

Based on a $1,935,000 cost of implementation for each unit, the net value for this SAMA is -$1,605,198 ($329,802 - $1,935,000) for Unit 1 and -$1,005,414 ($929,586 - $1,935,000) for Unit 2, which implies that this SAMA is not cost beneficial for either unit.

F.7.2.1.5 SAMA 21: Increase Reliability of PORV Closure

The RCS PORVs are designed to open to relieve RCS pressure during overpressure conditions. The valves are then required to reclose when pressure is reduced to below the valve set pressure (there is essentially no dead band associated with the PINGP PORV design). In the PRA model, failure of either PORV on a unit to reclose following a pressure challenge is assumed to result in a “PORV LOCA” initiating event, an event having an accident progression similar to a small-break LOCA event.

PORV failure-to-reclose events are significant contributors to the LERF, as certain initiating events (particularly MSLB events) involve pressure challenges that also involve secondary side depressurization. If the PORV failure leads to core damage at high RCS pressure, the potential exists for a pressure-induced SGTR which would provide a fission product release pathway outside of containment.

Assumptions:

1. To estimate an upper bound on the risk benefit for this SAMA, it was assumed that a new or enhanced PORV design was implemented, such that the valve re-closure probability was reduced by an order of magnitude.

PRA Model Changes to Model SAMA:

The only changes to the PRA necessary to model this SAMA were to reduce the probability of events representing failure of the PORV to reclose.

The table below shows the basic events that were modified to model this SAMA:

**SAMA 21 Changes to Basic Events**

| Description | Original Probability | SAMA21 Probability |
|---|---|---|
| PORV CV-31231 FAILS TO CLOSE | 2.94E-03 | 2.94E-04 |
| PORV CV-31232 FAILS TO CLOSE | 2.94E-03 | 2.94E-04 |
| PORV CV-31233 FAILS TO CLOSE | 2.94E-03 | 2.94E-04 |
| PORV CV-31234 FAILS TO CLOSE | 2.94E-03 | 2.94E-04 |

Results of SAMA Quantification:

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table for Units 1 and 2:

| | CDF | Dose-Risk | OECR |
|---|---|---|---|
| Unit $1_{Base}$ | 9.79E-06 | 2.93 | $15,852 |
| Unit $1_{SAMA}$ | 9.71E-06 | 2.91 | $15,644 |
| Unit 1 Percent Reduction | 0.8% | 0.7% | 1.3% |
| Unit $2_{Base}$ | 1.21E-05 | 8.43 | $63,337 |
| Unit $2_{SAMA}$ | 1.20E-05 | 8.40 | $63,114 |
| Unit 2 Percent Reduction | 0.7% | 0.4% | 0.4% |

A further breakdown of the Dose-risk and OECR information is provided below according to release category.

**SAMA 21 - Unit 1 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 7.28E-06 | 1.92E-06 | 2.82E-07 | 2.33E-07 | 5.61E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.79E-06** |
| $Frequency_{SAMA}$ | 7.20E-06 | 1.92E-06 | 2.82E-07 | 2.29E-07 | 5.57E-08 | 3.22E-08 | 3.09E-08 | 4.89E-09 | 8.40E-10 | 2.32E-11 | **9.71E-06** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.63 | 1.32 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.93** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.12 | 0.63 | 1.30 | 0.12 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **2.91** |
| $OECR_{BASE}$ | $0 | $18 | $961 | $11,706 | $741 | $2,408 | $0 | $0 | $18 | $0 | **$15,852** |
| $OECR_{SAMA}$ | $0 | $18 | $961 | $11,504 | $735 | $2,408 | $0 | $0 | $18 | $0 | **$15,644** |

**SAMA 21 - Unit 2 Results By Release Category**

| Release Category | H-XX-X | L-DH-L | L-CC-L | SGTR | L-H2-E | ISLOCA | H-DH-L | H-OT-L | L-CI-E | H-H2-E | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $Frequency_{BASE}$ | 8.52E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.52E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.21E-05** |
| $Frequency_{SAMA}$ | 8.44E-06 | 1.97E-06 | 3.39E-07 | 1.17E-06 | 6.47E-08 | 3.22E-08 | 3.14E-08 | 5.87E-09 | 9.17E-10 | 2.32E-11 | **1.20E-05** |
| $Dose\text{-}Risk_{BASE}$ | 0.01 | 0.12 | 0.76 | 6.66 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.43** |
| $Dose\text{-}Risk_{SAMA}$ | 0.01 | 0.12 | 0.76 | 6.64 | 0.14 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | **8.40** |
| $OECR_{BASE}$ | $0 | $19 | $1,157 | $58,874 | $860 | $2,408 | $0 | $0 | $19 | $0 | **$63,337** |
| $OECR_{SAMA}$ | $0 | $19 | $1,157 | $58,657 | $854 | $2,408 | $0 | $0 | $19 | $0 | **$63,114** |

This information was used in the cost-benefit calculation. The results of this calculation are provided in the following table.

**SAMA 21 Net Value**

| Unit | Base Case Cost-Risk | Revised Cost-Risk | Averted Cost-Risk |
|---|---|---|---|
| Unit 1 | $1,114,000 | $1,102,714 | $11,286 |
| Unit 2 | $2,980,000 | $2,967,482 | $12,518 |

As expected, the SAMA 21 results show the primary risk benefit to be the reduction in the frequency of release category L-SR-E (pressure and temperature-induced SGTR core damage sequences). This release category is a component of the LERF for both units, although the impact (percent change) on the Unit 1 LERF is larger than the change on Unit 2 due to the higher contribution from SGTR sequences on Unit 2 (as previously described).

Based on a $3,000,000 cost of implementation for each unit, the net value for this SAMA is -$2,988,714 ($11,286 - $3,000,000) for Unit 1 and -$2,987,482 ($12,518 - $3,000,000) for Unit 2, which implies that this SAMA is <u>not</u> cost beneficial for either unit.

### F.7.2.2 Phase II Impact

As discussed above, the 95$^{th}$ percentile PRA results for each individual Phase II SAMA were 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 95$^{th}$ percentile results for the Level 2 and 3 models, the same scaling factor calculated for the Level 1 results was applied to the Level 2 and 3 models. Because the MMACR calculations scale linearly with the CDF, dose-risk, and offsite economic cost-risk, the 95$^{th}$ percentile MMACR for each SAMA can be re-calculated by multiplying the base case by the 95$^{th}$ percentile for each of the individual SAMAs.

The Phase II SAMA list has been re-examined using the revised MMACR to identify SAMAs that would be re-characterized as cost beneficial, i.e., positive net value. Those SAMAs that were previously determined not cost beneficial due to costs of implementation that exceeded their associated MMACR are now potentially cost beneficial if the implementation costs are less than the revised MMACR. In this case, one additional Phase II SAMA (SAMA 22) becomes cost beneficial for Unit 1 and no additional SAMAs for Unit 2.

### F.7.2.3 Summary

The following table provides a summary of the impact of using the 95$^{th}$ percentile PRA results on the detailed cost-benefit calculations that have been performed for Phase II SAMAs and those Phase I SAMAs identified above in Section F.7.2.1

**Unit 1 Summary of the Impact of Using the 95th Percentile PRA Results**

| SAMA ID | Cost of Implementation | Averted Cost Risk (Base) | Net Value (Base) | Averted Cost Risk (95th Percentile) | Net Value (95th Percentile) | Change in Cost Effectiveness? |
|---|---|---|---|---|---|---|
| 1 | $4,250,000 | $268,252 | ($3,981,748) | $429,203 | ($3,820,797) | No |
| 2 | $300,000 | $123,376 | ($176,624) | $259,090 | ($40,910) | No |
| 3 | $250,000 | $74,956 | ($175,044) | $179,894 | ($70,106) | No |
| 5 | $1,500,000 | $75,942 | ($1,424,058) | $212,638 | ($1,287,362) | No |
| 9 | $62,500 | $62,746 | $246 | $163,140 | $100,640 | No |
| 10 | $2,866,000 | $46,870 | ($2,819,130) | $121,862 | ($2,744,138) | No |
| 12 | $900,000 | $186,188 | ($713,812) | $372,376 | ($527,624) | No |
| 15 | $130,000 | $0 | ($130,000) | $0 | ($130,000) | No |
| 17 | $2,362,000 | $88,030 | ($2,273,970) | $255,287 | ($2,106,713) | No |
| 19 | $700,000 | $60,330 | ($639,670) | $174,957 | ($525,043) | No |
| 19a | $1,935,000 | $329,802 | ($1,605,198) | $593,644 | ($1,341,356) | No |
| 20 | $313,000 | $53,910 | ($259,090) | $150,948 | ($162,052) | No |
| 21 | $3,000,000 | $11,286 | ($2,988,714) | $32,729 | ($2,967,271) | No |
| 22 | $39,000 | $15,350 | ($23,650) | $44,515 | $5,515 | Yes |

**Unit 2 Summary of the Impact of Using the 95th Percentile PRA Results**

| SAMA ID | Cost of Implementation | Averted Cost Risk (Base) | Net Value (Base) | Averted Cost Risk (95th Percentile) | Net Value (95th Percentile) | Change in Cost Effectiveness? |
|---|---|---|---|---|---|---|
| 1 | $4,250,000 | $270,474 | ($3,979,526) | $486,853 | ($3,763,147) | No |
| 2 | $300,000 | $123,092 | ($176,908) | $283,112 | ($16,888) | No |
| 3 | $250,000 | $76,654 | ($173,346) | $183,970 | ($66,030) | No |
| 5 | $1,500,000 | $222,610 | ($1,277,390) | $645,569 | ($854,431) | No |
| 9 | $62,500 | $62,918 | $418 | $157,295 | $94,795 | No |
| 10 | $2,866,000 | $48,630 | ($2,817,370) | $131,301 | ($2,734,699) | No |
| 12 | $900,000 | $302,132 | ($597,868) | $664,690 | ($235,310) | No |
| 15 | $130,000 | $19,324 | ($110,676) | $54,107 | ($75,893) | No |
| 17 | $2,362,000 | $488,118 | ($1,873,882) | $1,366,730 | ($995,270) | No |
| 19 | $700,000 | $60,514 | ($639,486) | $175,491 | ($524,509) | No |
| 19a | $1,935,000 | $929,586 | ($1,005,414) | $1,766,213 | ($168,787) | No |
| 20 | $313,000 | $54,646 | ($258,354) | $153,009 | ($159,991) | No |
| 21 | $3,000,000 | $12,518 | ($2,987,482) | $33,799 | ($2,966,201) | No |
| 22 | $39,000 | $67,650 | $28,650 | $189,420 | $150,420 | No |

In reviewing the above results, none of the Phase I SAMAs identified in Section F.7.2.1 proved to be cost-beneficial at the 95th percentile. When the 95th percentile PRA results were applied to the Phase II SAMAs, only SAMA 22 for Unit 1 was shown to now be marginally cost effective. The use of the 95th percentile PRA result is not considered to provide the most rational assessment of the cost effectiveness of a SAMA; however, this additional SAMA should be considered for implementation to address the uncertainties inherent in the SAMA risk analysis, especially since its consideration for Unit 2 was shown to provide a cost benefit.

### F.7.3 MACCS2 Input Variations

The MACCS2 model was developed using the best information available for the PINGP site; however, reasonable changes to modeling assumptions can lead to variations in the Level 3 results. In order to determine how certain assumptions could impact the SAMA results, a sensitivity analysis was performed on a group of parameters that has previously been shown to impact the Level 3 results. These parameters (and associated sensitivity cases) include:

- Meteorological data (PI2004; PI2005)
- Population estimates (PI30INC; PISIT00)
- Evacuation effectiveness (PISLOW)
- Radionuclide release characteristics (PIATM1; PIATM2)
- Recovery, decontamination, and resettlement factors (Intermediate Phase) (PICHR1, PICHR2)

The risk metrics produced by MACCS2 that are evaluated in the sensitivity analyses are the 50 mile population dose and the 50 mile offsite economic cost for Unit 2. (Similar impacts would be expected for Unit 1). The subsections below discuss the changes in these results for each of the sensitivity cases that are shown below. The final subsection, F.7.3.6, 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.

| Case | Description | Unit 2 Pop. Dose Risk Δ Base (%) | Unit 2 Cost Risk Δ Base (%) |
|---|---|---|---|
| PI2003 | Base Case (Year 2003 MET data) | -- | -- |
| PI2004 | Year 2004 MET data | -1.5% | -4.7% |
| PI2005 | Year 2005 MET data | -4.3% | -13.4% |
| PI30INC | Year 2034 population values increased uniformly 30% over base case. | 28.6% | 29.6% |
| PISit00 | Year 2000 population based (Base Case is Year 2034) | -39.2% | -39.3% |
| PISlow | Evacuation speed decreased 50% to 1.67 mph, 0.75 m/sec (Base Case is 3.35 mph). | 1.7% | 0% |
| PIATM1 | Release height set to ground level | 2.3% | -5.8% |
| PIATM2 | Plume thermal heat content set to ambient (i.e., buoyant plume rise not modeled) | negligible | -6.1% |
| PICHR1 | Long Term Phase starts immediately after the Early Phase is over (No Intermediate Phase; Base Case is 6 month Intermediate Phase) | 19.2% | -33.2% |
| PICHR2 | 1 Year Intermediate Phase following the Early Phase (Base Case is 6 month Intermediate Phase) | -15.3% | 34.9% |

### F.7.3.1 Meteorological Sensitivity

In addition to the base case meteorological data (year 2003), data is also analyzed for the years 2004 and 2005. Analysis of these alternate data sets yielded population dose-risks and offsite economic cost-risks that are lower than the 2003 data by at least 1.5 percent and by as much as 13.4 percent.

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 2003 data is conservatively chosen for PINGP given that it yielded the largest results.

### F.7.3.2 Population Sensitivity

Two population sensitivity cases (PI30INC, PISIT00) are analyzed to determine the dependence of population estimates on the MAACS2 results.

In case PI30INC, the baseline 2034 population is uniformly increased by 30 percent in all sectors of the 50-mile radius. This change increased the estimated population dose-risk and offsite economic cost by over 28 percent each.

A second population based sensitivity (PISIT00) is performed to determine the impact of using year 2000 census data rather than projecting to the end of the license renewal period (Year 2034). The baseline SAMA case is based on a population projection to year 2034 based on the population growth trends shown between the years 1990 and 2000. When year 2000 data is utilized, the overall dose-risk and OECR decrease, as expected. Specifically, the dose-risk and the OECR each decreased by about 39 percent.

The population sensitivity cases (PI30INC, PISIT00) demonstrate a significant dependence on population estimates. This is expected given that the population dose and offsite economic costs are primarily driven by the regional population.

### F.7.3.3 Evacuation Sensitivity

One evacuation sensitivity case (PISLOW) is analyzed to determine the impacts associated with evacuation assumptions. 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.

For PINGP, evacuation assumptions have a relatively minor impact on dose-risk. A 50 percent decrease in the evacuation speed increased the dose-risk by only approximately 2 percent.

The evacuation sensitivity case (PISLOW) demonstrates minor population dose-risk impacts associated with evacuation assumptions due to the relatively slow base case PINGP evacuation.

### F.7.3.4 Radioactive Release Sensitivity

The sensitivity cases PIATM1 and PIATM2 quantify the impact of the assumptions related to the height of the release and thermal energy of the plume, respectively. PIATM1 assumes that the release occurs at ground level rather than at an elevation that could correspond to a release through the stack or a break high in the reactor building. The lower release height shows a small increase in dose-risk of 2 percent and a reduction in OECR of over approximately 6 percent. Reducing the thermal plume heat content to ambient conditions has a similar impact. PIATM2 shows a negligible change (0 percent) in the dose-risk and a decrease of about 6 percent in the OECR.

### F.7.3.5 Intermediate Phase Duration Sensitivity

The Intermediate Phase, as modeled by MACCS2, is the time period beginning after the early phase (one week emergency phase) and extends to the time when recovery actions such as decontamination and resettlement are started (long term phase). MACCS2 allows the habitation of land during the intermediate phase unless the projected dose criterion is exceeded. If the projected dose criterion is exceeded during the intermediate phase, the individual is relocated. MACCS2 allows an intermediate phase ranging from no intermediate phase to one (1) year. The Intermediate Phase related sensitivity cases (PICHR1 and PICHR2) show significant dependence in relation to economic impact, and are therefore discussed further:

- The No Intermediate Phase case (PICHR1) is developed based on the NUREG-1150 modeling approach. However, the 33 percent reduction in economic cost estimates based on the approach are 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 example, the costs associated with temporary housing while decontamination strategies are developed and decontamination teams are contracted are not accounted for without an intermediate phase. It is believed that NUREG-1150 studies omitted the intermediate phase because the MACCS2 intermediate phase coding was not validated at that time. A competing factor is that the population dose increases because people are allowed to re-occupy the land sooner (19 percent increase over the base case).
- The 1 Year Intermediate Phase case (PICHR2) 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 the contaminated land is not performed during this phase even if contamination levels decrease (by natural radioactive decay) 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 over estimated using a long (i.e., one year) intermediate phase. An Intermediate Phase of one year shows a 35 percent increase in the OECR estimates compared with the six month (base case) Intermediate phase. However, the population dose decreased by 15 percent 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 a reasonable time for both decontamination efforts and resettlement to begin. The sensitivity cases demonstrate that this six month modeling approach is mid-range of the modeling choices available and is used as the base case.

### F.7.3.6 Impact on SAMA Analysis

Several different Level 3 input parameters are examined as part of the PINGP 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 increase in the dose-risk is 29 percent in the population sensitivity case PI30INC (2034 population uniformly increased by 30%) while the largest increase in OECR is 35 percent in the intermediate phase duration sensitivity case PICHR2 (one year intermediate phase). While these are separate cases, the PINGP MMACR is recalculated using these results to determine the impact of using the worst case for each parameter simultaneously. The resulting Unit 2 MMACR is a factor of 1.24 greater than the base case, which is less than the average factor of 2.5 calculated in Section F.7.2 for the 95$^{th}$ percentile individual SAMA PRA model results. Therefore, the 95$^{th}$ percentile PRA results sensitivity 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 Unit 2 Containment Sump Sensitivity Analysis

As described in Section F.2.2.2, the Unit 2 SAMA probabilistic analysis results were quantified using the Unit 2, Level 1 Rev. 2.2 (SAMA) model. At the time of the Rev. 2.2 model update, containment sump strainer modifications to address G.L. 2004-02 on Unit 2 had not been completed. However, during the Unit 2 refueling outage in Fall 2006 (prior to the submittal of this LAR), the containment sump modifications were completed. Therefore, a sensitivity analysis is considered necessary to demonstrate the impact of this significant plant modification to the results of the Unit 2 SAMA analysis.

The containment sump strainer modifications implemented in Unit 1 and Unit 2 are very similar in design and operation. Therefore, in order to perform this sensitivity analysis, the reliability (assumed plugging failure rate) for the Unit 2 sump strainers was reduced to match the failure rate of the Unit 1 sump strainers (reduced by an order of magnitude). The probabilistic analyses for each of the Phase II SAMAs were re-performed, and the results used to regenerate new averted cost values for each of the SAMAs.

The results of the sensitivity analysis showed the change in averted costs were on the order of a few thousand dollars or less for most of the identified Phase II SAMAs when accounting for a more reliable sump strainer for Unit 2. However, this did not change the overall outcome for Unit 2 regarding whether or not a particular SAMA was cost-beneficial. The change in averted costs due to the implementation of a more reliable containment sump strainer for Unit 2 is judged to be within the statistical uncertainty of the SAMA analysis.

The Unit 2 Level 1 PRA model used for the SAMA analysis is therefore deemed slightly conservative in the sense that the modeled reliability of the strainer is less than the actual plant configuration following the Fall 2006 outage. However, the sensitivity analysis showed that this does not affect the applicability of using the existing Level 1 model for Unit 2.

## F.8 CONCLUSIONS

The benefits of revising the operational strategies in place at PINGP and/or implementing hardware modifications can be evaluated without the insight from a risk-based analysis. Use of the PRA in conjunction with cost-benefit analysis methodologies has, however, provided an enhanced understanding of the effects of the proposed changes relative to the cost of implementation and projected impact on a larger future population. The results of this study indicate that of the identified potential improvements that can be made at PINGP, a few are cost beneficial based on the methodology applied in this analysis and warrant further review for potential implementation. It should be noted that the following conclusions were drawn based on the use of a 3% RDR, which is viewed as a more appropriate discount rate. However, if a 7% RDR were used, there would be fewer SAMAs identified as being cost-beneficial.

### F.8.1 Unit 1 Conclusions

The base case analysis shows that implementation of the following SAMA for Unit 1 would be cost beneficial:

- SAMA 9: Analyze Room Heat-up for Natural/Forced Circulation (Screenhouse Ventilation)

SAMA 9 is a potentially cost beneficial enhancement at PINGP. This SAMA represents engineering analyses and possible procedure modifications that loss of Screenhouse Ventilation is not expected to fail operation of the safeguards vertical cooling water (CL) pumps. Computer modeling of expected room temperatures due to maximum mechanical and electrical heat loads during summer operation is anticipated to show that running electrical equipment would continue to successfully operate for a 24 hour mission time, with minimal mitigative efforts by equipment operators, e.g., opening doors, dampers, etc.

The 95$^{th}$ percentile PRA results showed that the following additional SAMA was cost beneficial for Unit 1:

- SAMA22: Provide Compressed Air Backup for Instrument Air to Containment

SAMA 22 is a cost-effective change for PINGP, given the results of the sensitivity analysis involving 95$^{th}$ percentile PRA values (see Section F.7.2). This SAMA deals with analyzing the actual capability of the backup air accumulators for adequate operation of the PORV during bleed and feed operation in removing heat from the primary system when the steam generators are unavailable. On a loss of instrument air to containment, the PORVs are each supplied with air from separate backup air accumulators. However, it is suspected that the air requirements during bleed and feed operations may be less than that required for overpressure conditions. Previous analyses involving these air accumulators included conservative assumptions and operating conditions that implied PORV operation would be compromised given a loss of the normal air supply. Therefore, a more realistic analysis of the PORV backup air accumulators, using the expected procedural sequence of operator actions, is expected to show that additional hardware modification is unnecessary. However, costs for any required procedural changes or plant modifications resulting from this analysis were not included in the SAMA cost estimate (S&L 2007).

### F.8.2 Unit 2 Conclusions

The base case analysis shows that implementation of the following two SAMAs for Unit 2 would be cost beneficial:

- SAMA 9: Analyze Room Heat-up for Natural/Forced Circulation (Screenhouse Ventilation)
- SAMA22: Provide Compressed Air Backup for Instrument Air to Containment

The discussion of these SAMAs in Section F.8.1 applies to Unit 2 as well.

The 95$^{th}$ percentile PRA results showed that there were no additional cost beneficial SAMAs for Unit 2.

## F.9 TABLES

**Table F.3-1**
**Estimated Population Distribution within a 10-Mile Radius of PINGP, Year 2034[2]**

| Sector | 0-1 mile (1.84) [1] | 1-2 miles (1.21) [1] | 2-3 miles (1.00) [1] | 3-4 miles (1.03) [1] | 4-5 miles (1.02) [1] | 5-10 miles (1.09) [1] | 10-mile total |
|---|---|---|---|---|---|---|---|
| N | 0 | 14 | 25 | 25 | 16 | 493 | 573 |
| NNE | 0 | 109 | 34 | 137 | 41 | 712 | 1033 |
| NE | 0 | 143 | 30 | 0 | 52 | 868 | 1093 |
| ENE | 0 | 0 | 9 | 0 | 30 | 553 | 592 |
| E | 0 | 0 | 134 | 0 | 100 | 461 | 695 |
| ESE | 0 | 0 | 0 | 81 | 124 | 2810 | 3015 |
| SE | 0 | 0 | 0 | 0 | 228 | 17066 | 17294 |
| SSE | 0 | 0 | 0 | 864 | 856 | 575 | 2295 |
| S | 0 | 91 | 0 | 856 | 228 | 311 | 1486 |
| SSW | 0 | 0 | 20 | 57 | 78 | 415 | 570 |
| SW | 0 | 0 | 20 | 1 | 140 | 409 | 570 |
| WSW | 0 | 0 | 47 | 0 | 0 | 347 | 394 |
| W | 142 | 0 | 0 | 26 | 70 | 716 | 954 |
| WNW | 1349 | 10 | 1 | 141 | 7 | 2377 | 3885 |
| NW | 208 | 19 | 0 | 18 | 0 | 647 | 892 |
| NNW | 125 | 0 | 0 | 34 | 0 | 999 | 1158 |
| Total | 1824 | 386 | 320 | 2240 | 1970 | 29759 | 36499 |

(1) Ten year radial population growth factor applied to year 2000 census data to develop year 2034 estimate.
(2) Population estimates are based on year 2000 census data as processed by SECPOP2000. Any minor differences from the population estimates and actual population are judged to have a negligible impact on the results given the MACCS2 modeling methodology.

**Table F.3-2**
**Estimated Population Distribution within a 50-Mile Radius of PINGP, Year 2034[2]**

| Sector | 0-10 miles | 10-20 miles (1.18) [1] | 20-30 miles (1.34) [1] | 30-40 miles (1.10) [1] | 40-50 miles (1.12) [1] | 50-mile total |
|---|---|---|---|---|---|---|
| N | 573 | 27938 | 36153 | 23733 | 17081 | 105478 |
| NNE | 1033 | 3290 | 17862 | 3660 | 12635 | 38480 |
| NE | 1093 | 8039 | 11719 | 6543 | 6963 | 34357 |
| ENE | 592 | 2167 | 6284 | 24257 | 12927 | 46227 |
| E | 695 | 1647 | 5869 | 6240 | 8427 | 22878 |
| ESE | 3015 | 2784 | 12460 | 7073 | 3564 | 28896 |
| SE | 17294 | 1555 | 9864 | 7079 | 4809 | 40601 |
| SSE | 2295 | 1988 | 5839 | 20093 | 62859 | 93074 |
| S | 1486 | 2771 | 21155 | 35417 | 61632 | 122461 |
| SSW | 570 | 1575 | 6412 | 3852 | 7529 | 19938 |
| SW | 570 | 3642 | 9064 | 23698 | 47250 | 84224 |
| WSW | 394 | 9691 | 53668 | 11743 | 14428 | 89924 |
| W | 954 | 4230 | 64056 | 53846 | 35935 | 159021 |
| WNW | 3885 | 21326 | 250009 | 460884 | 409761 | 1145865 |
| NW | 892 | 35228 | 445530 | 838915 | 749278 | 2069843 |
| NNW | 1158 | 5115 | 141140 | 134921 | 66497 | 348831 |
| Total | 36499 | 132986 | 1097084 | 1661954 | 1521575 | 4450098 |

(1) Ten year radial population growth factor applied to year 2000 census data to develop year 2034 estimate.

(2) Population estimates are based on year 2000 census data as processed by SECPOP2000. Any minor differences from the population estimates and actual population are judged to have a negligible impact on the results given the MACCS2 modeling methodology.

**Table F.3-3**
**Comparison of PINGP MACCS2 Core Inventory and Sample Problem A**

| Entry | Nuclide(2) | Sample Problem A(1) (Bq) | PINGP MACCS2(3) (Bq) | Entry | Nuclide(2) | Sample Problem A(1) (Bq) | PINGP MACCS2(3) (Bq) |
|---|---|---|---|---|---|---|---|
| 1 | Co-58 | 1.56E+16 | 2.17E+16 | 31 | Te-131m | 2.26E+17 | 2.63E+17(3) |
| 2 | Co-60 | 1.19E+16 | 1.66E+16 | 32 | Te-132 | 2.25E+18 | 2.41E+18(3) |
| 3 | Kr-85 | 1.20E+16 | 2.55E+16(3) | 33 | I-131 | 1.55E+18 | 1.70E+18(3) |
| 4 | Kr-85m | 5.60E+17 | 4.07E+17(3) | 34 | I-132 | 2.28E+18 | 2.44E+18(3) |
| 5 | Kr-87 | 1.02E+18 | 7.77E+17(3) | 35 | I-133 | 3.28E+18 | 3.40E+18(3) |
| 6 | Kr-88 | 1.38E+18 | 1.07E+18(3) | 36 | I-134 | 3.60E+18 | 3.66E+18(3) |
| 7 | Rb-86 | 9.13E+14 | 1.27E+15 | 37 | I-135 | 3.09E+18 | 3.15E+18(3) |
| 8 | Sr-89 | 1.74E+18 | 2.41E+18 | 38 | Xe-133 | 3.28E+18 | 3.40E+18(3) |
| 9 | Sr-90 | 9.37E+16 | 1.30E+17 | 39 | Xe-135 | 6.16E+17 | 7.03E+17(3) |
| 10 | Sr-91 | 2.23E+18 | 3.10E+18 | 40 | Cs-134 | 2.09E+17 | 7.40E+17(3) |
| 11 | Sr-92 | 2.32E+18 | 3.23E+18 | 41 | Cs-136 | 6.36E+16 | 1.48E+17(3) |
| 12 | Y-90 | 1.01E+17 | 1.40E+17 | 42 | Cs-137 | 1.17E+17 | 3.15E+17(3) |
| 13 | Y-91 | 2.12E+18 | 2.94E+18 | 43 | Ba-139 | 3.04E+18 | 4.22E+18 |
| 14 | Y-92 | 2.33E+18 | 3.24E+18 | 44 | Ba-140 | 3.01E+18 | 4.18E+18 |
| 15 | Y-93 | 2.64E+18 | 3.67E+18 | 45 | La-140 | 3.07E+18 | 4.27E+18 |
| 16 | Zr-95 | 2.67E+18 | 3.72E+18 | 46 | La-141 | 2.82E+18 | 3.92E+18 |
| 17 | Zr-97 | 2.78E+18 | 3.87E+18 | 47 | La-142 | 2.72E+18 | 3.78E+18 |
| 18 | Nb-95 | 2.53E+18 | 3.51E+18 | 48 | Ce-141 | 2.73E+18 | 3.80E+18 |
| 19 | Mo-99 | 2.95E+18 | 4.10E+18 | 49 | Ce-143 | 2.66E+18 | 3.70E+18 |
| 20 | Tc-99m | 2.55E+18 | 3.54E+18 | 50 | Ce-144 | 1.65E+18 | 2.29E+18 |
| 21 | Ru-103 | 2.20E+18 | 3.05E+18 | 51 | Pr-143 | 2.61E+18 | 3.63E+18 |
| 22 | Ru-105 | 1.43E+18 | 1.99E+18 | 52 | Nd-147 | 1.17E+18 | 1.62E+18 |
| 23 | Ru-106 | 4.99E+17 | 6.94E+17 | 53 | Np-239 | 3.13E+19 | 4.35E+19 |
| 24 | Rh-105 | 9.89E+17 | 1.38E+18 | 54 | Pu-238 | 1.77E+15 | 2.46E+15 |
| 25 | Sb-127 | 1.35E+17 | 1.87E+17 | 55 | Pu-239 | 4.00E+14 | 5.56E+14 |
| 26 | Sb-129 | 4.77E+17 | 6.64E+17 | 56 | Pu-240 | 5.04E+14 | 7.01E+14 |
| 27 | Te-127 | 1.30E+17 | 1.70E+17(3) | 57 | Pu-241 | 8.49E+16 | 1.18E+17 |
| 28 | Te-127m | 1.72E+16 | 2.59E+16(3) | 58 | Am-241 | 5.60E+13 | 7.79E+13 |
| 29 | Te-129 | 4.48E+17 | 5.18E+17(3) | 59 | Cm-242 | 2.15E+16 | 2.98E+16 |
| 30 | Te-129m | 1.18E+17 | 1.48E+17(3) | 60 | Cm-244 | 1.26E+15 | 1.75E+15 |

(1) Core inventory obtained from MACCS2 Sample Problem A, adjusted to account for the PINGP power level

(2) MACCS2 allows up to 60 nuclides input

(3) PINGP USAR Appendix D, Rev. 18 Table D.1-1 provides 20 significant nuclide core inventories. These values are converted from Curies to Becquerels (3.7E10 bq/ci) for input into MACCS2. The remaining 40 nuclides inventories are based on Sample Problem A, adjusted to account for the PINGP power level, and increased by the average increase over the Sample Problem A inventory of the 20 PINGP specific nuclides.

**Table F.3-4**
**MACCS2 Release Categories vs. PINGP Release Categories**

| MACCS2 Release Categories | PINGP Release Categories(3) |
|---|---|
| 1-Xe/Kr | Noble Gases |
| 2-I | CsI |
| 3-Cs | CsOH |
| 4-Te | TeO2 (Sb(1) & Te2(2) are included) |
| 5-Sr | SrO |
| 6-Ru(Mo) | MoO2 (Mo is in Ru MACCS category) |
| 7-La | La2O3 |
| 8-Ce | CeO2 (UO2(2) are included) |
| 9-Ba | BaO |

(1) The largest release fraction of the TeO2 and Sb category is used
(2) These release fractions are typically negligible.
(3) Fission product groups from Table F.3-6 are grouped into Release Categories for input into MACCS2.

**Table F.3-5**
**Representative MAAP Level 2 Case Descriptions and Key Event Timings**

| Case | Release Category | NMC Release Class(es)(1) | Representative Case Description | Tcd(2) (Hrs) | Tvf(3) (Hrs) | Tcf(4) (Hrs) | Tend(5) (Hrs) | Noble Gas Fraction | CsI(6) Fraction |
|---|---|---|---|---|---|---|---|---|---|
| 1 | H-XX-X | 1X-XX-X<br>1L-XX-X<br>1H-XX-X | Core Damage, No Containment Failure (containment leakage only); No Rx Vessel Failure -or- Rx Vessel Failure at Low Pressure -or- Rx Vessel Failure at High Pressure | 2.54 | 4.00 | N/A | 48 | 1.00E-03 | 3.00E-06 |
| 2 | H-H2-E | 1H-CI-E<br>1H-H2-E | Core Damage, Rx Vessel Failure at High Pressure, Early Containment Failure Due to Containment Isolation Failure -or- Overpressure Due to Hydrogen Combustion (or DCH, In-Vessel/Ex-Vessel Steam Explosions, etc.) | 2.54 | 3.99 | 3.99 | 48 | 6.60E-01 | 1.80E-02 |
| 3 | L-H2-E | 1L-H2-E<br>1X-H2-E | Core Damage, Early Containment Failure on Overpressure Due to Hydrogen Combustion (or DCH, In-Vessel/Ex-Vessel Steam Explosions, etc.; Rx Vessel Failure at Low Pressure -or- No Rx Vessel Failure | 7.40 | 9.01 | 9.01 | 48 | 7.50E-01 | 2.30E-02 |
| 4 | L-CI-E | 1L-CI-E<br>1X-CI-E | Core Damage, Early Containment Failure Due to Containment Isolation Failure; No Rx Vessel Failure -or- Rx Vessel Failure at Low Pressure | 7.79 | 9.38 | N/A | 48 | 6.90E-01 | 3.30E-02 |
| 5 | H-OT-L | 1H-OT-L | Core Damage, Rx Vessel Failure at High Pressure, Late Containment Failure on Overtemperature or Overpressure | 2.54 | 4.00 | 40.00 | 64 | 9.10E-01 | 6.00E-04 |
| 6 | L-CC-L | 1L-CC-L | Core Damage, Rx Vessel Failure at Low RCS Pressure, Late Containment Failure due to Core Concrete Interaction | 0.27 | 0.81 | 40.00 | 64 | 1.00E+00 | 1.80E-03 |
| 7 | H-DH-L | 1H-DH-L | Core Damage, Rx Vessel Failure at High Pressure, Late Containment Failure on Overpressure Due to Failure to Remove Decay Heat | 2.54 | 3.99 | 40.00 | 64 | 1.00E+00 | 6.00E-05 |
| 8 | L-DH-L | 1L-DH-L | Core Damage, Rx Vessel Failure at Low Pressure, Late Containment Failure on Overpressure Due to Failure to Remove Decay Heat | 7.17 | 9.96 | 40.00 | 64 | 1.00E+00 | 3.00E-05 |

**Table F.3-5 (Continue)**
**Representative MAAP Level 2 Case Descriptions and Key Event Timings**

| Case | Release Category | NMC Release Class(es)[(1)] | Representative Case Description | Tcd[(2)] (Hrs) | Tvf[(3)] (Hrs) | Tcf[(4)] (Hrs) | Tend[(5)] (Hrs) | Noble Gas Fraction | CsI[(6)] Fraction |
|---|---|---|---|---|---|---|---|---|---|
| 9 | SGTR | 1GEH<br>1GLH<br>1L-SR-E | Early Core Damage -or- Late Core Damage from Steam Generator Tube Rupture, Containment Bypass (RCS at High Pressure) -or- Pressure- or Temperature-Induced SGTR | 24.12 | 26.31 | N/A | 48 | 9.60E-01 | 3.50E-01 |
| 10 | ISLOCA | 1ISLOCA | Early Core Damage at High or Low Pressure with Containment Bypass from Intersystem LOCA | 0.38 | 0.86 | N/A | 48 | 1.00E+00 | 7.60E-01 |

Notes to Table F.3-5

(1) Unit 2 CETs and release categories are identical except for a “2” designator in the first character of each name

(2) Tcd - Time of core damage (maximum core temperature > 1800°F)

(3) Tvf - Time of vessel breach

(4) Tcf – Time of containment failure

(5) Tend – Time at end of run

(6) CsI – Cesium Iodide release

**Table F.3-6**
**Prairie Island Source Term Summary**

| | Release Category | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | H-XX-X | H-H2-E | L-H2-E | L-CI-E | H-OT-L | L-CC-L | H-DH-L | L-DH-L | SGTR | ISLOCA |
| Bin Frequency | | | | | | | | | | |
| Run Duration | 48 hr | 48 hr | 48 hr | 48 hr | 64 hr | 64 hr | 64 hr | 64 hr | 48 hr | 48 hr |
| Time after Scram when General Emergency is declared (3) | 2.6 hr | 2.6 hr | 7.7 hr | 8.1 hr | 2.6 hr | .7 hr | 2.6 hr | 7.5 hr | 24.1 hr | .8 hr |
| Fission Product Group: | | | | | | | | | | |
| 1) Noble | | | | | | | | | | |
| Total Plume 1 Release Fraction | 1.00E-03 | 6.60E-01 | 7.50E-01 | 6.90E-01 | 9.10E-01 | 1.00E+00 | 1.00E+00 | 1.00E+00 | 9.60E-01 | 1.00E+00 |
| Start of Plume 1 Release (hr) | 2.50 | 4.00 | 9.00 | 8.00 | 40.00 | 40.00 | 40.00 | 40.00 | 24.00 | 0.80 |
| End of Plume 1 Release (hr) | 48.00 | 4.00 | 9.00 | 10.00 | 40.00 | 40.00 | 40.00 | 40.00 | 26.00 | 0.80 |
| Total Plume 2 Release Fraction[2] | | | | | | | | | | |
| Start of Plume 2 Release (hr) | | | | | | | | | | |
| End of Plume 2 Release (hr) | | | | | | | | | | |
| 2) CsI | | | | | | | | | | |
| Total Plume 1 Release Fraction | 3.00E-06 | 1.80E-02 | 2.30E-02 | 3.30E-02 | 6.00E-04 | 1.80E-03 | 6.00E-05 | 3.00E-05 | 3.50E-01 | 7.60E-01 |
| Start of Plume 1 Release (hr) | 2.50 | 4.00 | 9.00 | 8.00 | 40.00 | 40.00 | 40.00 | 40.00 | 24.00 | 0.80 |
| End of Plume 1 Release (hr) | 10.00 | 4.00 | 9.00 | 10.00 | 64.00 | 40.00 | 40.00 | 40.00 | 26.00 | 0.80 |
| Total Plume 2 Release Fraction[2] | | | | | | 4.00E-03 | | 5.50E-05 | | |
| Start of Plume 2 Release (hr) | | | | | | 40.00 | | 40.00 | | |
| End of Plume 2 Release (hr) | | | | | | 64.00 | | 64.00 | | |
| 3) TeO2 | | | | | | | | | | |
| Total Plume 1 Release Fraction | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 1.00E-05 | 0.00E+00 | 2.00E-10 | 0.00E+00 | 5.00E-06 |
| Start of Plume 1 Release (hr) | | | | | | 40.00 | | 40.00 | | 2.00 |
| End of Plume 1 Release (hr) | | | | | | 40.00 | | 40.00 | | 2.00 |
| Total Plume 2 Release Fraction[2] | | | | | | | | | | |
| Start of Plume 2 Release (hr) | | | | | | | | | | |
| End of Plume 2 Release (hr) | | | | | | | | | | |

**Table F.3-6**
**Prairie Island Source Term Summary (Continued)**

| | Release Category | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | H-XX-X | H-H2-E | L-H2-E | L-CI-E | H-OT-L | L-CC-L | H-DH-L | L-DH-L | SGTR | ISLOCA |
| 4) SrO | | | | | | | | | | |
| Total Plume 1 Release Fraction | 1.50E-08 | 1.50E-04 | 2.00E-05 | 2.50E-05 | 3.00E-07 | 5.00E-06 | 5.00E-07 | 1.00E-08 | 3.00E-04 | 2.50E-02 |
| Start of Plume 1 Release (hr) | 2.50 | 4.00 | 9.00 | 8.00 | 40.00 | 40.00 | 40.00 | 40.00 | 24.00 | 0.80 |
| End of Plume 1 Release (hr) | 10.00 | 4.00 | 9.00 | 10.00 | 40.00 | 40.00 | 40.00 | 40.00 | 26.00 | 2.00 |
| Total Plume 2 Release Fraction[2] | | | | | | | | | | |
| Start of Plume 2 Release (hr) | | | | | | | | | | |
| End of Plume 2 Release (hr) | | | | | | | | | | |
| 5) MoO2 | | | | | | | | | | |
| Total Plume 1 Release Fraction | 8.00E-07 | 8.00E-03 | 2.80E-04 | 7.00E-05 | 2.00E-05 | 1.60E-07 | 2.00E-05 | 3.00E-08 | 2.00E-04 | 8.00E-04 |
| Start of Plume 1 Release (hr) | 2.50 | 4.00 | 9.00 | 8.00 | 40.00 | 40.00 | 40.00 | 40.00 | 24.00 | 0.80 |
| End of Plume 1 Release (hr) | 10.00 | 4.00 | 9.00 | 10.00 | 40.00 | 40.00 | 40.00 | 40.00 | 26.00 | 0.80 |
| Total Plume 2 Release Fraction[2] | | | | | | | | | | |
| Start of Plume 2 Release (hr) | | | | | | | | | | |
| End of Plume 2 Release (hr) | | | | | | | | | | |
| 6) CsOH | | | | | | | | | | |
| Total Plume 1 Release Fraction | 3.00E-06 | 1.80E-02 | 2.30E-02 | 3.30E-02 | 8.00E-04 | 4.00E-03 | 4.00E-05 | 7.00E-05 | 3.30E-01 | 7.60E-01 |
| Start of Plume 1 Release (hr) | 2.50 | 4.00 | 9.00 | 8.00 | 40.00 | 40.00 | 40.00 | 40.00 | 24.00 | 0.80 |
| End of Plume 1 Release (hr) | 10.00 | 4.00 | 9.00 | 10.00 | 64.00 | 40.00 | 40.00 | 40.00 | 26.00 | 0.80 |
| Total Plume 2 Release Fraction[2] | | | | | | 1.20E-02 | | 1.50E-04 | | |
| Start of Plume 2 Release (hr) | | | | | | 40.00 | | 40.00 | | |
| End of Plume 2 Release (hr) | | | | | | 64.00 | | 64.00 | | |

**Table F.3-6**
**Prairie Island Source Term Summary (Continued)**

| | Release Category | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | H-XX-X | H-H2-E | L-H2-E | L-CI-E | H-OT-L | L-CC-L | H-DH-L | L-DH-L | SGTR | ISLOCA |
| 7) BaO | | | | | | | | | | |
| Total Plume 1 Release Fraction | 1.50E-07 | 1.80E-03 | 1.50E-04 | 2.00E-04 | 3.00E-06 | 4.00E-06 | 5.00E-06 | 1.50E-07 | 2.00E-03 | 1.40E-02 |
| Start of Plume 1 Release (hr) | 2.50 | 4.00 | 9.00 | 8.00 | 40.00 | 40.00 | 40.00 | 40.00 | 24.00 | 0.80 |
| End of Plume 1 Release (hr) | 10.00 | 4.00 | 9.00 | 10.00 | 40.00 | 40.00 | 40.00 | 40.00 | 26.00 | 2.00 |
| Total Plume 2 Release Fraction[2] | | | | | | | | | | |
| Start of Plume 2 Release (hr) | | | | | | | | | | |
| End of Plume 2 Release (hr) | | | | | | | | | | |
| 8) La2O3 | | | | | | | | | | |
| Total Plume 1 Release Fraction | 7.00E-07 | 4.50E-04 | 3.00E-07 | 1.00E-02 | 4.00E-07 | 2.00E-06 | 1.00E-06 | 2.00E-05 | 6.00E-04 | 1.10E-01 |
| Start of Plume 1 Release (hr) | 2.50 | 4.00 | 9.00 | 9.00 | 40.00 | 1.00 | 40.00 | 40.00 | 26.00 | 0.80 |
| End of Plume 1 Release (hr) | 10.00 | 4.00 | 9.00 | 10.00 | 40.00 | 1.00 | 40.00 | 40.00 | 26.00 | 0.80 |
| Total Plume 2 Release Fraction[2] | | | | | | 3.80E-06 | | | | |
| Start of Plume 2 Release (hr) | | | | | | 40.00 | | | | |
| End of Plume 2 Release (hr) | | | | | | 64.00 | | | | |
| 9) CeO2 | | | | | | | | | | |
| Total Plume 1 Release Fraction | 7.00E-07 | 4.50E-04 | 1.20E-06 | 1.00E-02 | 4.00E-07 | 2.00E-06 | 1.00E-06 | 2.00E-05 | 6.50E-04 | 1.10E-01 |
| Start of Plume 1 Release (hr) | 2.50 | 4.00 | 9.00 | 9.00 | 40.00 | 1.00 | 40.00 | 40.00 | 26.00 | 0.80 |
| End of Plume 1 Release (hr) | 10.00 | 4.00 | 9.00 | 10.00 | 40.00 | 1.00 | 40.00 | 40.00 | 26.00 | 0.80 |
| Total Plume 2 Release Fraction[2] | | | | | | 6.50E-06 | | | | |
| Start of Plume 2 Release (hr) | | | | | | 40.00 | | | | |
| End of Plume 2 Release (hr) | | | | | | 40.00 | | | | |

**Table F.3-6**
**Prairie Island Source Term Summary (Continued)**

| | Release Category | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | H-XX-X | H-H2-E | L-H2-E | L-CI-E | H-OT-L | L-CC-L | H-DH-L | L-DH-L | SGTR | ISLOCA |
| 10) Sb | | | | | | | | | | |
| Total Plume 1 Release Fraction | 2.80E-06 | 2.10E-02 | 2.50E-03 | 3.50E-03 | 1.50E-03 | 8.00E-03 | 1.00E-04 | 2.00E-05 | 6.80E-02 | 3.40E-01 |
| Start of Plume 1 Release (hr) | 2.50 | 4.00 | 9.00 | 8.00 | 40.00 | 40.00 | 40.00 | 40.00 | 24.00 | 0.80 |
| End of Plume 1 Release (hr) | 10.00 | 4.00 | 9.00 | 10.00 | 64.00 | 40.00 | 40.00 | 40.00 | 26.00 | 4.00 |
| Total Plume 2 Release Fraction[2] | | | | | | 2.00E-02 | 5.00E-04 | 5.50E-05 | | |
| Start of Plume 2 Release (hr) | | | | | | 40.00 | 40.00 | 40.00 | | |
| End of Plume 2 Release (hr) | | | | | | 64.00 | 64.00 | 64.00 | | |
| 11) Te2 | | | | | | | | | | |
| Total Plume 1 Release Fraction | 0.00E+00 | 0.00E+00 | 1.20E-04 | 8.00E-05 | 0.00E+00 | 4.00E-03 | 0.00E+00 | 1.50E-07 | 2.00E-03 | 3.60E-01 |
| Start of Plume 1 Release (hr) | | | 9.00 | 9.00 | | 40.00 | | 40.00 | 28.00 | 0.80 |
| End of Plume 1 Release (hr) | | | 9.00 | 10.00 | | 40.00 | | 40.00 | 30.00 | 2.00 |
| Total Plume 2 Release Fraction[2] | | | | | | | | 3.00E-07 | | |
| Start of Plume 2 Release (hr) | | | | | | | | 40.00 | | |
| End of Plume 2 Release (hr) | | | | | | | | 64.00 | | |
| 12) UO2 | | | | | | | | | | |
| Total Plume 1 Release Fraction | 0.00E+00 | 0.00E+00 | 6.00E-09 | 4.00E-09 | 0.00E+00 | 2.00E-08 | 0.00E+00 | 0.00E+00 | 1.00E-07 | 7.00E-05 |
| Start of Plume 1 Release (hr) | | | 9.00 | 9.00 | | 40.00 | | | 28.00 | 0.80 |
| End of Plume 1 Release (hr) | | | 9.00 | 10.00 | | 40.00 | | | 30.00 | 2.00 |
| Total Plume 2 Release Fraction[2] | | | | | | | | | | |
| Start of Plume 2 Release (hr) | | | | | | | | | | |
| End of Plume 2 Release (hr) | | | | | | | | | | |

(1) Puff releases are denoted in the table by those entries with equivalent start and end times.

(2) Plume 2 release fraction is cumulative and includes the initial plume 1 release fraction
(3) General Emergency declaration based on time of core damage per Prairie Island EAL Reference Manual, Rev 0

**Table F.3-7**
**MACCS2 Base Case Mean Results**

| Source Term | Release Category | Dose (p-sv)(1) | Offsite Economic Cost ($) | Unit 1 Freq. (/yr) | Unit 1 Dose-Risk (p-rem/yr)(1) | Unit 1 OECR ($/yr) | Unit 2 Freq. (/yr) | Unit 2 Dose-Risk (p-rem/ yr)(1) | Unit 2 OECR ($/yr) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | H-XX-X | 1.75E+01 | 1.35E+02 | 7.28E-06 | 1.27E-02 | 9.83E-04 | 8.52E-06 | 1.49E-02 | 1.15E-03 |
| 2 | H-H2-E | 2.12E+04 | 1.05E+10 | 2.32E-11 | 4.91E-05 | 2.43E-01 | 2.32E-11 | 4.91E-05 | 2.43E-01 |
| 3 | L-H2-E | 2.15E+04 | 1.15E+10 | 5.61E-08 | 1.21E-01 | 6.46E+02 | 6.52E-08 | 1.40E-01 | 7.50E+02 |
| 4 | L-CL-E | 3.40E+04 | 1.85E+10 | 8.40E-10 | 2.86E-03 | 1.55E+01 | 9.17E-10 | 3.12E-03 | 1.70E+01 |
| 5 | H-OT-L | 2.63E+03 | 4.74E+07 | 4.89E-09 | 1.29E-03 | 2.32E-01 | 5.87E-09 | 1.54E-03 | 2.78E-01 |
| 6 | L-CC-L | 2.26E+04 | 2.97E+09 | 2.82E-07 | 6.37E-01 | 8.37E+02 | 3.39E-07 | 7.67E-01 | 1.01E+03 |
| 7 | H-DH-L | 2.11E+02 | 1.02E+06 | 3.09E-08 | 6.53E-04 | 3.16E-02 | 3.14E-08 | 6.63E-04 | 3.21E-02 |
| 8 | L-DH-L | 6.68E+02 | 7.89E+06 | 1.92E-06 | 1.28E-01 | 1.52E+01 | 1.97E-06 | 1.32E-01 | 1.55E+01 |
| 9 | SGTR | 5.62E+04 | 4.32E+10 | 2.33E-07 | 1.31E+00 | 1.01E+04 | 1.17E-06 | 6.58E+00 | 5.06E+04 |
| 10 | ISLOCA | 2.26E+05 | 6.31E+10 | 3.22E-08 | 7.28E-01 | 2.03E+03 | 3.22E-08 | 7.28E-01 | 2.03E+03 |
| **FREQUENCY WEIGHTED TOTALS** | | | | **9.85E-06** | **2.94E+00** | **1.36E+04** | **1.21E-05** | **8.37E+00** | **5.44E+04** |

(1) MAACS2 provides dose results in Sieverts (sv). The MAACS2 result is converted to rem (1 sv = 100 rem) for the Dose-Risk results to be used in Section F.4.

**Table F.5-1a**
**Unit 1 Level 1 Importance List Review**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0SLOCAXXCDY | 1.90E-02 | 1.62 | OPERATOR FAILS TO PERFORM RCS COOLDOWN AND DEPRESSURIZATION ON SMALL LOCA | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates. (No specific SAMA identified) |
| 0HRECIRCC2Y | 5.30E-02 | 1.588 | OPERATOR FAILS TO INITIATE HH RECIRC COND. ON FAILURE OF RCS COOLDOWN AND DEPRESSURIZATION | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates.<br><br>Install control logic to automatically swap to recirculation mode of ECCS, and drawing suction from RB sump prior to depletion of RWST. (SAMA 1) |
| 1RCPSL | 1.00E+00 | 1.352 | RCP SEAL LOCA FLAG | This flag identifies the importance of all RCP seal LOCA contributors. RCP seal LOCA failures will be addressed elsewhere in this table. (No specific SAMA identified) |
| I-1-SLOCAA | 1.80E-03 | 1.326 | LOOP A SMALL LOCA INITIATOR | This initiator identifies all Loop A small LOCA initiating events and is based on industry data. The specific contributors that make SLOCAs important are addressed individually in this table. (No specific SAMA identified) |
| I-1-SLOCAB | 1.80E-03 | 1.326 | LOOP B SMALL LOCA INITIATOR | This initiator identifies all Loop B small LOCA initiating events and is based on industry data. The specific contributors that make SLOCAs important are addressed individually in this table. (No specific SAMA identified) |

**Table F.5-1a**
**Unit 1 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| I-LOCL | 1.00E+00 | 1.22 | LOSS OF COOLING WATER INITIATING EVENT FREQUENCY | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |
| 1LVM32060XN | 3.00E-03 | 1.141 | VALVE MV-32060 FAILS TO OPEN | This valve provides suction source from RWST to charging pumps for seal injection. Local actuation of this valve could mitigate remote operation failures. However, operator recovery actions may only provide limited benefit due to the high uncertainty involved. Consider installing air operated valve in parallel to provide continuous suction source of water from RWST. (SAMA 3) |

**Table F.5-1a**
**Unit 1 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| I-LOOP | 3.20E-02 | 1.118 | LOOP INITIATOR FREQUENCY | The importance of the LOOP initiator flag provides limited information about plant risk given that the LOOP category is broad and includes several different contributors. These contributors are represented by other events in this importance list that better define specific failures that can be investigated to identify means of reducing plant risk. No credible means of reducing the PI LOOP frequency have been identified. Implementation of the Maintenance Rule is considered to address equipment reliability issues such that no measurable improvement is likely available based on enhancing maintenance practices. It may be possible to improve switchyard work planning and/or practices, but a reliable means of quantifying the impact of these types of changes is not available. (No specific SAMA identified) |
| 0SMP11XXXYR | 9.55E-02 | 1.112 | 11 CL PUMP FAILS TO RUN (1 YEAR MISSION TIME) | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |

**Table F.5-1a**
**Unit 1 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0SMP21XXXYR | 9.55E-02 | 1.112 | 21 CL PUMP FAILS TO RUN (1 YEAR MISSION TIME) | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |
| 0FAILROSP1Y | 2.88E-01 | 1.094 | OPERATOR FAILS TO RESTORE OFFSITE POWER 1 HOUR AFTER SBO | A diesel driven, HPI pump that could use a large volume, cold suction source would reduce the risk of LOOP by prolonging the time the plant can operate without offsite AC power. (SAMA 5)<br><br>In addition, the ability to cross-tie emergency 4kV AC buses would allow the operators to power functional equipment in divisions where the corresponding EDG has failed. (SAMA 7) |
| 0SPD22XXXXR | 3.91E-02 | 1.094 | 22 CL PUMP FAILS TO RUN (DIESEL DRIVER) | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |

**Table F.5-1a**
**Unit 1 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0FAILROSP6Y | 1.71E-01 | 1.065 | OPERATOR FAILS TO RESTORE OFFSITE POWER WITH OA7 SUCCESS AND HI FLOW RCP SEAL LE | A diesel driven, HPI pump that could use a large volume, cold suction source would reduce the risk of LOOP by prolonging the time the plant can operate without offsite AC power. (SAMA 5)<br><br>The ability to cross-tie emergency 4kV AC buses would allow the operators to power functional equipment in divisions where the corresponding EDG has failed. (SAMA 7)<br><br>Installation of a swing or SBO diesel would provide increased defense in depth and could be considered for LOOP conditions. (SAMA 8)<br><br>Consider enhancing the PRA to credit recovery of operator failure based on TSC and EOF oversight. (No specific SAMA identified) |
| 1NOCONLOCA | 1.00E+00 | 1.052 | NO CONSEQUENTIAL LOCA FLAG | This event is informational and categorizes those small LOCAs that do not involve stuck open relief valves. (No specific SAMA identified) |
| 0SPD12XXXXR | 3.91E-02 | 1.049 | 12 CL PUMP FAILS TO RUN (DIESEL DRIVER) | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |

**Table F.5-1a**
**Unit 1 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| I-1-TR4 | 9.10E-02 | 1.041 | LOSS OF MFW INITIATING EVENT FREQUENCY | This initiating event frequency is based on plant operating experience and takes into account IPE recommendation no. 2 (see Section F.5.1.5). Equipment performance and reliability could be enhanced if key components were added to the MR. (No specific SAMA identified) |
| 2AG7D5XXXXR | 5.64E-02 | 1.04 | D5 DIESEL GENERATOR FAILS TO RUN | Installation of a swing or SBO diesel of a different design would provide increased defense in depth and could be considered for loss of onsite emergency AC power sources. (SAMA 8) |
| 0SED11RFEXS | 4.80E-03 | 1.035 | 11 SAFEGUARDS SCREENHOUSE ROOF EXHAUST FAN FAILS TO START | Failure of safeguards screenhouse roof exhaust fans fails the associated cooling water pumps. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth without having to rely on the opposite train of cooling water. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (see SAMA 2)<br><br>Further analysis such as room heatup calculations could be considered to determine to what extent natural or forced circulation can adequately remove heat from the affected areas, for example, portable fans, open doors, etc. (SAMA 9) |

**Table F.5-1a**
**Unit 1 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 1LBI112BXXE | 7.46E-04 | 1.031 | BISTABLE 1-LC-112BX FAILS TO FUNCTION | Failure of this level controller disables the RWST auto transfer feature, rendering the RWST unavailable as an alternate water source to the charging pumps. Alternate means of RWST transfer could be developed, either procedurally or via plant modification. For example, parallel level transmitter signal path that could prevent a spurious failure of any one signal rendering suction unavailable to the charging pumps. A 2 out of 2 level control logic would be required for auto transfer of charging pump suction. (SAMA 10) |
| 1LBI141BXXE | 7.46E-04 | 1.031 | BISTABLE 1-LC-141BX FAILS TO FUNCTION | Failure of this level controller disables the RWST auto transfer feature, rendering the RWST unavailable as an alternate water source to the charging pumps. Alternate means of RWST transfer could be developed, either procedurally or via plant modification. For example, parallel level transmitter signal path that could prevent a spurious failure of any one signal rendering suction unavailable to the charging pumps. A 2 out of 2 level control logic would be required for auto transfer of charging pump suction. (SAMA 10) |
| 0HRECIRCXXY | 9.50E-03 | 1.03 | OPERATOR FAILS TO INITATE HIGH HEAD RECIRC. FOR A MEDIUM LOCA | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates.<br><br>Consider installation of control logic to automatically swap to recirculation mode of ECCS, and drawing suction from RB sump prior to depletion of RWST. (SAMA 1) |

**Table F.5-1a**
**Unit 1 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| I-1-LOCC | 1.00E+00 | 1.03 | LOSS OF COMPONENT COOLING WATER INITIATING EVENT FREQUENCY | An alternate source of water could be made available to provide the necessary cooling for RCP thermal barriers. Consider using FPS as a means to provide backup cooling source. This can be accomplished by connecting FPS directly to component cooling system header. A release path will be required since FPS is not a closed system. (SAMA 12) |
| 0RRECIRCXXY | 6.80E-02 | 1.029 | OPERATOR FAILS TO INITIATE LOW HEAD RECIRC. WHEN REQUIRED | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates.<br><br>Consider installation of control logic to automatically swap to recirculation mode of ECCS, and drawing suction from RB sump prior to depletion of RWST. (SAMA 1) |
| 2AG7D6XXXXR | 5.64E-02 | 1.029 | D6 DIESEL GENERATOR FAILS TO RUN | Installation of a swing or SBO diesel of a different design would provide increased defense in depth and could be considered for loss of onsite emergency AC power sources. (SAMA 8) |
| 0SDCXXXXCCR | 1.66E-03 | 1.026 | 12, 22 CL PUMPS FAIL TO RUN DUE TO CCF OF DIESEL DRIVERS | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |

**Table F.5-1a**
**Unit 1 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0SE211RFCCS | 2.03E-04 | 1.025 | 11, 21 SAFEGUARDS SCREENHOUSE ROOF EXHAUST FANS FAIL TO START DUE TO CCF | Failure of safeguards screenhouse roof exhaust fans fails the associated cooling water pumps. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth without having to rely on the opposite train of cooling water. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (see SAMA 2)<br><br>Further analysis such as room heatup calculations could be considered to determine to what extent natural or forced circulation can adequately remove heat from the affected areas, for example, portable fans, open doors, etc. (SAMA 9) |
| 0SPM121XXPM | 1.39E-02 | 1.025 | 121 CL PUMP UNAVAILABLE DUE TO PREVENTIVE MAINTENANCE | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |

**Table F.5-1a**
**Unit 1 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 1AG5D2XXXXR | 4.63E-02 | 1.025 | D2 DIESEL GENERATOR FAILS TO RUN | Installation of a swing or SBO diesel of a different design would provide increased defense in depth and could be considered for loss of onsite emergency AC power sources. (SAMA 8) |
| I-1-TR1 | 7.00E-01 | 1.025 | NORMAL TRANSIENT INITIATING EVENT FREQUENCY | The importance of the Normal Transient initiator provides limited information about plant risk given that the transient category is broad and includes several different contributors. These contributors are represented by other events in this importance list that better define specific failures that can be investigated to identify means of reducing plant risk. No credible means of reducing the PI Normal Transient frequency have been identified. Implementation of the Maintenance Rule is considered to address equipment reliability issues such that no measurable improvement is likely available based on enhancing maintenance practices. It may be possible to improve BOP work planning and/or practices, but a reliable means of quantifying the impact of these types of changes is not available. (No specific SAMA identified) |

**Table F.5-1a**
**Unit 1 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0AB7FLDISLY | 3.30E-03 | 1.024 | OPERATOR FAILS TO ISOLATE AUXILIARY BUILDING ZONE 7 FLOODING SOURCE | This initiator represents an internal flooding scenario that disables various safety-related components. Mitigation of this event can be accomplished via an automatic sump pump system to remove water if the operator fails to isolate Zone 7 of the Aux. Bldg. (SAMA 13)<br><br>Consider installing waterproof (EQ) equipment (valves / level sensors) capable of automatically isolating the flooding source. (SAMA 6)<br><br>Consider segregating this zone into 2 compartments to reduce the impact of a flood on both trains of SI and RHR. (SAMA 6a) |
| 1AG5D1XXXXR | 4.63E-02 | 1.024 | D1 DIESEL GENERATOR FAILS TO RUN | Installation of a swing or SBO diesel of a different design would provide increased defense in depth and could be considered for loss of onsite emergency AC power sources. (SAMA 8) |
| 0SPCHZXYCCR | 3.50E-03 | 1.021 | 11 AND 21 HORIZONTAL CL PUMPS FAIL TO RUN DUE TO CCF (1 YEAR MISSION TIME) | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |

**Table F.5-1a**
**Unit 1 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0SDM34137XN | 2.88E-03 | 1.02 | CD-34137 FAILS TO OPEN (11 SAFEGUARDS SCREENHOUSE ROOF EXHAUST DAMPER) | Failure of safeguards screenhouse roof exhaust fans fails the associated cooling water pumps. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth without having to rely on the opposite train of cooling water. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |
| 1NOSBO | 1.00E+00 | 1.02 | NO STATION BLACKOUT FLAG | This flag provides information only on the nature of the cutset that leads to core damage (CD). The only information conveyed is that the accident sequence does not involve SBO. (No specific SAMA identified) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0SLOCAXXCDY | 1.90E-02 | 1.533 | OPERATOR FAILS TO PERFORM RCS COOLDOWN AND DEPRESSURIZATION ON SMALL LOCA | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates. (No specific SAMA identified) |
| 0HRECIRCC2Y | 5.30E-02 | 1.43 | OPERATOR FAILS TO INITIATE HH RECIRC COND. ON FAILURE OF RCS COOLDOWN AND DEPRESSURIZATION. | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates.<br><br>Install control logic to automatically swap to recirculation mode of ECCS, and drawing suction from RB sump prior to depletion of RWST. (SAMA 1) |
| I-2-SLOCAA | 1.80E-03 | 1.287 | LOOP A SMALL LOCA INITIATOR | This initiator identifies all Loop A small LOCA initiating events and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. (No specific SAMA identified) |
| I-2-SLOCAB | 1.80E-03 | 1.287 | LOOP B SMALL LOCA INITIATOR | This initiator identifies all Loop B small LOCA initiating events and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. (No specific SAMA identified) |
| 2RCPSL | 1.00E+00 | 1.279 | RCP SEAL LOCA FLAG | This flag identifies the importance of all RCP seal LOCA contributors. RCP seal LOCA failures will be addressed elsewhere in this table. (No specific SAMA identified) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| I-LOCL | 1.00E+00 | 1.172 | LOSS OF COOLING WATER INITIATING EVENT FREQUENCY | Failure of the cooling water system may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |
| 2LVM32062XN | 3.00E-03 | 1.113 | VALVE MV-32062 FAILS TO OPEN | This valve provides suction source from RWST to charging pumps for seal injection. Local actuation of this valve could mitigate remote operation failures. However, operator recovery actions may only provide limited benefit due to the high uncertainty involved. Consider installing air operated valve in parallel to provide continuous suction source of water from RWST. (SAMA 3) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| I-LOOP | 3.20E-02 | 1.106 | LOOP INITIATOR FREQUENCY | The importance of the LOOP initiator flag provides limited information about plant risk given that the LOOP category is broad and includes several different contributors. These contributors are represented by other events in this importance list that better define specific failures that can be investigated to identify means of reducing plant risk. No credible means of reducing the PI LOOP frequency have been identified. Implementation of the Maintenance Rule is considered to address equipment reliability issues such that no measurable improvement is likely available based on enhancing maintenance practices. It may be possible to improve switchyard work planning and/or practices, but a reliable means of quantifying the impact of these types of changes is not available. (No specific SAMA identified) |
| 0SMP11XXXYR | 9.55E-02 | 1.089 | 11 CL PUMP FAILS TO RUN (1 YEAR MISSION TIME) | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0SMP21XXXYR | 9.55E-02 | 1.089 | 21 CL PUMP FAILS TO RUN (1 YEAR MISSION TIME) | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |
| 0FAILROSP1Y | 2.88E-01 | 1.084 | OPERATOR FAILS TO RESTORE OFFSITE POWER 1 HOUR AFTER SBO | A diesel driven, HPI pump that could use a large volume, cold suction source would reduce the risk of LOOP by prolonging the time the plant can operate without offsite AC power. (SAMA 5)<br><br>Finally, the ability to cross-tie emergency 4kV AC buses would allow the operators to power functional equipment in divisions where the corresponding EDG has failed. (SAMA 7) |
| 0SGTRXXXCDY | 9.20E-03 | 1.08 | OPERATOR FAILS TO COOLDOWN AND DEPRESSURIZE RCS FOR A SGTR BEFORE SG OVERFILL | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates. (No specific SAMA identified) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 2RSTSUMPBXF | 7.20E-03 | 1.078 | CONTAINMENT SUMP B STRAINER PLUGS DUE TO DEBRIS | This event inhibits or prevents recirculation from the containment sump to the RCS during a small LOCA condition. A potential SAMA could address the source of debris and removal or reinforcement of any equipment such that the likelihood of clogging is reduced.<br>In addition, consideration of a different type of strainer, or multiple strainers, could provide added reliability of recirculation. (SAMA 24) |
| 2NOCONLOCA | 1.00E+00 | 1.077 | NO CONSEQUENTIAL LOCA FLAG | This event is informational and categorizes those small LOCAs that do not involve stuck open relief valves. (No specific SAMA identified) |
| 0SPD22XXXXR | 3.91E-02 | 1.075 | 22 CL PUMP FAILS TO RUN (DIESEL DRIVER) | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0FAILROSP6Y | 1.71E-01 | 1.057 | OPERATOR FAILS TO RESTORE OFFSITE POWER WITH OA7 SUCCESS AND HI FLOW RCP SEAL LE | A diesel driven, HPI pump that could use a large volume, cold suction source would reduce the risk of LOOP by prolonging the time the plant can operate without offsite AC power. (SAMA 5)<br><br>The ability to cross-tie emergency 4kV AC buses would allow the operators to power functional equipment in divisions where the corresponding EDG has failed. (SAMA 7)<br><br>Installation of a swing or SBO diesel would provide increased defense in depth and could be considered for LOOP conditions. (SAMA 8) |
| I-2-SGTRA | 4.50E-03 | 1.049 | 21 SG STEAM GENERATOR TUBE RUPTURE INITIATING EVENT FREQ. | This initiator identifies all unit 2A steam generator tube rupture initiating events and is based on industry data. Therefore, mitigative actions will be addressed elsewhere in this table. Consider upgrading SG to more robust design to lower accident frequency. Consider replenishing the RWST from a large source of water, such as the SFP, if failure to depressurize is part of the scenario. (SAMA 19a) |
| I-2-SGTRB | 4.50E-03 | 1.049 | 22 SG STEAM GENERATOR TUBE RUPTURE INITIATING EVENT FREQ. | This initiator identifies all unit 2B steam generator tube rupture initiating events and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. Consider upgrading SG to more robust design to lower accident frequency. Consider replenishing the RWST from a large source of water, such as the SFP, if failure to depressurize is part of the scenario. (SAMA 19a) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 2SGTRRLFFTC | 5.00E-01 | 1.045 | SG RELIEF FAILS TO CLOSE FOLLOWING SG OVERFILL (SGTR) | Reinforce operator training to isolate PORVs when symptoms reveal valves have failed to re-seat. This reduces the amount of radioactivity released to the environment. Consider replacing with more reliable or robust valves to better isolate following lifting. (SAMA 14) |
| 2SGTRRLFSUC | 5.00E-01 | 1.045 | SUCCESSFUL SG RELIEF VALVE CLOSURE FOLLOWING SG OVERFILL (SGTR) | This event represents successful closure of SG relief valve following SG overfill. See above for additional information. (No specific SAMA identified) |
| 2AG7D5XXXXR | 5.64E-02 | 1.044 | D5 DIESEL GENERATOR FAILS TO RUN | Installation of a swing or SBO diesel would provide increased defense in depth and could be considered for loss of onsite emergency AC power sources. (SAMA 8) |
| 0SGTRXXEC3Y | 5.80E-03 | 1.042 | OPERATOR FAILS IN USE OF ECA-3.1/3.2 FOLLOWING SG OVERFILL (SGTR) | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates. (No specific SAMA identified) |
| 0SPD12XXXXR | 3.91E-02 | 1.041 | 12 CL PUMP FAILS TO RUN (DIESEL DRIVER) | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| I-2-TR4 | 9.10E-02 | 1.035 | LOSS OF MFW INITIATING EVENT FREQUENCY | This initiating event frequency is based on plant operating experience and takes into account IPE recommendation no. 2 (see Section F.5.1.5). Equipment performance and reliability could be enhanced if key components were added to the MR. (No specific SAMA identified) |
| 0EOPHXCONXY | 2.30E-02 | 1.034 | OPERATOR FAILS TO LINE UP OTHER UNIT MDAFW PUMP | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates. Consider installing a spare turbine-driven AFW pump per unit. This would increase reliability of AFW system for each unit. The new pumps would be dedicated to the corresponding unit with no cross-tie capability, thereby eliminating operator error for this action. Note - some operating PWRs have (3) AFW pumps per unit, which provide greater redundancy and defense in depth. (SAMA 18) |
| I-2-LODCA | 8.80E-04 | 1.034 | LOSS OF TRAIN A DC INITIATOR FREQUENCY | Consider a portable DC power source, such as a rectifier or skid-mounted battery pack that could be used for restoring DC control power to vital components, such as breakers, solenoid valves, etc. (SAMA 15) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 2RVM32169XN | 3.00E-03 | 1.032 | MV-32169 FAILS TO OPEN | Failure of MV-32169 to open disables RHR Loop B return. Proper operation of this valve is most likely tracked via the MR. Consider replacing this MOV with a fail closed (FC) air-operated valve for improved reliability. This would eliminate CCF for inboard MOVs that currently exist on this flowpath. (SAMA 16)<br><br>Alternatively, a bypass flowpath could be installed around inboard RHR Loop B return valves for improved defense in depth. (SAMA 17) |
| 2AG7D6XXXXR | 5.64E-02 | 1.031 | D6 DIESEL GENERATOR FAILS TO RUN | Installation of a swing or SBO diesel would provide increased defense in depth and could be considered for loss of onsite emergency AC power sources. (SAMA 8) |
| 2EPT22AFTXR | 2.01E-02 | 1.031 | 22 AF PUMP FAILS TO RUN (TURBINE DRIVER PORTION) | Consider installing a spare turbine-driven AFW pump per unit. This would increase reliability of AFW system for each unit. The new pumps would be dedicated to the corresponding unit with no cross-tie capability, thereby eliminating operator error for this action. Note - some operating PWRs have (3) AFW pumps per unit, which provide greater redundancy and defense in depth. (SAMA 18) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0SED11RFEXS | 4.80E-03 | 1.028 | 11 SAFEGUARDS SCREENHOUSE ROOF EXHAUST FAN FAILS TO START | Failure of safeguards screenhouse roof exhaust fans fails the associated cooling water pumps. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth without having to rely on the opposite train of cooling water. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2)<br><br>Further analysis such as room heatup calculations could be considered to determine to what extent natural or forced circulation can adequately remove heat from the affected areas, for example, portable fans, open doors, etc. (SAMA 9) |
| 2LBI112BXXE | 7.46E-04 | 1.025 | BISTABLE 2-LC-112BX FAILS TO FUNCTION | Failure of this level controller disables the RWST auto transfer feature, rendering the RWST unavailable as an alternate water source to the charging pumps (in the event cooling water is lost). Alternate means of RWST transfer could be developed, either procedurally or via plant modification (SAMA 10).<br><br>Auto transfer logic improvements, such as improved level controller reliability could also be considered. (SAMA 11) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 2LBI141BXXE | 7.46E-04 | 1.025 | BISTABLE 2-LC-141BX FAILS TO FUNCTION | Failure of this level controller disables the RWST auto transfer feature, rendering the RWST unavailable as an alternate water source to the charging pumps (in the event cooling water is lost). Alternate means of RWST transfer could be developed, either procedurally or via plant modification (SAMA 10).<br><br>Auto transfer logic improvements, such as improved level controller reliability could also be considered. (SAMA 11) |
| I-2-LOCC | 1.00E+00 | 1.025 | LOSS OF COMPONENT COOLING WATER INITIATING EVENT FREQUENCY | An alternate source of water could be made available to provide the necessary cooling for RCP thermal barriers. Consider using FPS as a means to provide backup cooling source. This can be accomplished by connecting FPS directly to component cooling system header. A release path will be required since FPS is not a closed system. (SAMA 12) |
| 0HRECIRCXXY | 9.50E-03 | 1.024 | OPERATOR FAILS TO INITATE HIGH HEAD RECIRC. FOR A MEDIUM LOCA | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates.<br><br>Consider installation of control logic to automatically swap to recirculation mode of ECCS, and drawing suction from RB sump prior to depletion of RWST. (SAMA 1) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| I-2-TR1 | 7.00E-01 | 1.024 | NORMAL TRANSIENT INITIATING EVENT FREQUENCY | The importance of the Normal Transient initiator provides limited information about plant risk given that the transient category is broad and includes several different contributors. These contributors are represented by other events in this importance list that better define specific failures that can be investigated to identify means of reducing plant risk. No credible means of reducing the PI Normal Transient frequency have been identified. Implementation of the Maintenance Rule is considered to address equipment reliability issues such that no measurable improvement is likely available based on enhancing maintenance practices. It may be possible to improve BOP work planning and/or practices, but a reliable means of quantifying the impact of these types of changes is not available. (No specific SAMA identified) |
| 0RRECIRCXXY | 6.80E-02 | 1.023 | OPERATOR FAILS TO INITIATE LOW HEAD RECIRC. WHEN REQUIRED | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates.<br><br>Consider installation of control logic to automatically swap to recirculation mode of ECCS, and drawing suction from RB sump prior to depletion of RWST. (SAMA 1) |
| I-2-MLOCAA | 1.50E-05 | 1.023 | LOOP A MEDIUM LOCA INITIATOR | This initiator identifies all Loop A medium LOCA initiating events and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. (No specific SAMA identified) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| I-2-MLOCAB | 1.50E-05 | 1.023 | LOOP B MEDIUM LOCA INITIATOR | This initiator identifies all Loop B medium LOCA initiating events and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. (No specific SAMA identified) |
| 0FDBLDOPATY | 1.70E-01 | 1.022 | OPERATOR FAIL TO ESTABLISH BLEED & FEED COND. ON RESTORING FEEDWATER | This is a conditional operator action failure probability that is dependent on failure of an earlier operator action. Restoration of AFW would render this event unnecessary. Therefore, consider installing a spare turbine-driven AFW pump per unit. This would increase reliability of AFW system for each unit. The new pumps would be dedicated to the corresponding unit with no cross-tie capability, thereby eliminating operator error for this action. Note - some operating PWRs have (3) AFW pumps per unit, which provide greater redundancy and defense in depth. (SAMA 18) |
| 0SDCXXXXCCR | 1.66E-03 | 1.022 | 12, 22 CL PUMPS FAIL TO RUN DUE TO CCF OF DIESEL DRIVERS | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0AB7FLDISLY | 3.30E-03 | 1.02 | OPERATOR FAILS TO ISOLATE AUXILIARY BUILDING ZONE 7 FLOODING SOURCE | This initiator represents an internal flooding scenario that disables various safety-related components. Mitigation of this event could be accomplished via an automatic sump pump system to remove water if the operator fails to isolate Zone 7 of the Aux. Bldg. (SAMA 13) |
| 0SE211RFCCS | 2.03E-04 | 1.02 | 11, 21 SAFEGUARDS SCREENHOUSE ROOF EXHAUST FANS FAIL TO START DUE TO CCF | Failure of safeguards screenhouse roof exhaust fans fails the associated cooling water pumps. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth without having to rely on the opposite train of cooling water. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2)<br><br>Further analysis such as room heatup calculations could be considered to determine to what extent natural or forced circulation can adequately remove heat from the affected areas, for example, portable fans, open doors, etc. (SAMA 9) |

**Table F.5-1b**
**Unit 2 Level 1 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0SPM121XXPM | 1.39E-02 | 1.02 | 121 CL PUMP UNAVAILABLE DUE TO PREVENTIVE MAINTENANCE | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |

**Table F.5-2a**
**Unit 1 Level 2 Importance List Review**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0SLOCAXXCDY | 1.90E-02 | 1.613 | OPERATOR FAILS TO PERFORM RCS COOLDOWN AND DEPRESSURIZATION ON SMALL LOCA | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates. (No specific SAMA identified) |
| I-1-ISLOCA | 1.00E+00 | 1.579 | INTERFACING SYSTEM LOCA INITIATING EVENT FREQUENCY | This initiator identifies all interfacing system LOCA initiating events and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. (No specific SAMA identified) |
| 1NORVSTKOPN | 8.35E-01 | 1.556 | NO DEPRESSURIZATION DUE TO PORV/SRV STUCK OPEN DURING CYCLING | This event conveys information that the PORV did not fail to re-seat following pressure relief; therefore no failure mechanism involved. (No specific SAMA identified) |
| 1TISGTRPROB | 5.53E-03 | 1.501 | 2-LOOP W PWR TEMPERATURE-INDUCED SGTR PROBABILITY | This basic event represents a phenomenological event for Level 2 accident scenarios. It is based on Westinghouse PWR analyses. No SAMA required. |
| 0HRECIRCC2Y | 5.30E-02 | 1.281 | OPERATOR FAILS TO INITIATE HH RECIRC COND. ON FAILURE OF RCS COOLDOWN AND DEPRESSURIZATION. | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates.<br><br>Consider installation of control logic to automatically swap to recirculation mode of ECCS, and drawing suction from RB sump prior to depletion of RWST. (SAMA 1) |
| 1HPIPERUP | 4.00E-03 | 1.266 | CONDITIONAL PROBABILITY OF LP PIPING RUPTURE WHEN EXPOSED TO RCS PRESSURE | This basic event represents a phenomenological event for Level 2 accident scenarios. (No specific SAMA identified) |

**Table F.5-2a**
**Unit 1 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 1SGTRECD | 1.00E+00 | 1.227 | SGTR SEQUENCES INVOLVING EARLY CORE DAMAGE | This flag identifies the importance of SGTR sequences that involve early core damage. Component failures will be addressed elsewhere in this table. (No specific SAMA identified) |
| 0SGTRXXCD1Y | 5.00E-02 | 1.223 | OPERATOR FAILS TO COOLDOWN AND DEPRESSURIZE RCS WITH SI FAILURE FOR A SGTR | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates. (No specific SAMA identified) |
| I-1-SLOCAA | 1.80E-03 | 1.146 | LOOP A SMALL LOCA INITIATOR | This initiator identifies all Loop A small LOCA initiating events and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. (No specific SAMA identified) |
| I-1-SLOCAB | 1.80E-03 | 1.146 | LOOP B SMALL LOCA INITIATOR | This initiator identifies all Loop B small LOCA initiating events and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. (No specific SAMA identified) |
| 1RVH32164XL | 1.31E-04 | 1.105 | MV-32164 (LP A HL TO RHR SUCTION) CATASTROPHIC LEAK (POWER TO VALVE REMOVED) | For Loop A/B HL return to RHR suction, consider upgrading piping downstream of inboard containment isolation valve to handle RCS pressure and install outboard containment isolation valve to prevent possible ISLOCA. RHR piping downstream of newly installed valve can remain as is. (SAMA 19) |

**Table F.5-2a**
**Unit 1 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 1RVH32230XL | 1.31E-04 | 1.105 | MV-32230 (LP B HL TO RHR SUCTION) CATASTROPHIC LEAK | For Loop A/B HL return to RHR suction, consider upgrading piping downstream of inboard containment isolation valve to handle RCS pressure and install outboard containment isolation valve to prevent possible ISLOCA. RHR piping downstream of newly installed valve can remain as is. (SAMA 19) |
| I-1-SGTRA | 7.98E-04 | 1.102 | 11 SG STEAM GENERATOR TUBE RUPTURE INITIATING EVENT FREQ. | This initiator identifies SGTR initiating events for 11 / 12 SG and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. Consider replenishing the RWST from a large source of water, such as the SFP, if failure to depressurize is part of the scenario. (SAMA 19a) |
| I-1-SGTRB | 7.98E-04 | 1.102 | 12 SG STEAM GENERATOR TUBE RUPTURE INITIATING EVENT FREQ. | This initiator identifies SGTR initiating events for 11 / 12 SG and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. Consider replenishing the RWST from a large source of water, such as the SFP, if failure to depressurize is part of the scenario. (SAMA 19a) |
| 1RVM32165XL | 2.63E-03 | 1.099 | MV-32165 (LP A HL TO RHR SUCTION) FAILS TO REMAIN CLOSED | For Loop A/B HL return to RHR suction, consider upgrading piping downstream of inboard containment isolation valve to handle RCS pressure and install outboard containment isolation valve to prevent possible ISLOCA. RHR piping downstream of newly installed valve can remain as is. (SAMA 19) |

**Table F.5-2a**
**Unit 1 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 1RVM32231XL | 2.63E-03 | 1.099 | MV-32231 (LP B HL TO RHR SUCTION) FAILS TO REMAIN CLOSED | For Loop A/B HL return to RHR suction, consider upgrading piping downstream of inboard containment isolation valve to handle RCS pressure and install outboard containment isolation valve to prevent possible ISLOCA. RHR piping downstream of newly installed valve can remain as is. (SAMA 19) |
| 1HVCSI95XXL | 1.31E-03 | 1.092 | CHECK VALVE SI-9-5 CATASTROPHIC LEAK | This check valve is in series with a second check valve (SI-9-3), both prevent backflow from the RCS to the SI system. Both check valves are inside containment with a normally open motor-operated valve upstream (also inside containment). Consider operating with the MOV normally closed, provided that an automatic open signal is sent to the valve for injection from the RWST under a LOCA condition. (SAMA 20) |
| 1HVCSI96XXL | 1.31E-03 | 1.092 | CHECK VALVE SI-9-6 CATASTROPHIC INTERNAL LEAK | This check valve is in series with a second check valve (SI-9-4), both prevent backflow from the RCS to the SI system. Both check valves are inside containment with a normally open motor-operated valve upstream (also inside containment). Consider operating with the MOV normally closed, provided that an automatic open signal is sent to the valve for injection from the RWST under a LOCA condition. (SAMA 20) |
| 1RCPSL | 1.00E+00 | 1.088 | RCP SEAL LOCA FLAG | This flag identifies the importance of all RCP seal LOCA contributors. RCP seal LOCA failures will be addressed elsewhere in this table. (No specific SAMA identified) |

**Table F.5-2a**
**Unit 1 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 1HVCSI93XXL | 1.31E-03 | 1.085 | CHECK VALVE SI-9-3 CATASTROPHIC LEAK | This check valve is in series with a second check valve (SI-9-5), both prevent backflow from the RCS to the SI system. Both check valves are inside containment with a normally open motor-operated valve upstream (also inside containment). Consider operating with the MOV normally closed, provided that an automatic open signal is sent to the valve for injection from the RWST under a LOCA condition. (SAMA 20) |
| 1HVCSI94XXL | 1.31E-03 | 1.085 | CHECK VALVE SI-9-4 CATASTROPHIC INTERNAL LEAK | This check valve is in series with a second check valve (SI-9-6), both prevent backflow from the RCS to the SI system. Both check valves are inside containment with a normally open motor-operated valve upstream (also inside containment). Consider operating with the MOV normally closed, provided that an automatic open signal is sent to the valve for injection from the RWST under a LOCA condition. (SAMA 20) |
| 1PISGTRSECB | 1.00E+00 | 1.084 | PRESSURE-INDUCED SGTR PROBABILITY FOR MSLB/MFLB EVENTS WITH HIGH/DRY SG | This flag identifies pressure-induced SGTR scenarios due to high differential pressure across the SG tubes. Components related to this event will be addressed elsewhere in this table. (No specific SAMA identified) |

**Table F.5-2a**
**Unit 1 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| I-LOCL | 1.00E+00 | 1.067 | LOSS OF COOLING WATER INITIATING EVENT FREQUENCY | Failure of the cooling water system may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |
| 1PORVLOCA | 1.00E+00 | 1.053 | TRANSIENT INDUCED PORV LOCA FLAG | This flag identifies those scenarios whereby the PORV fails to re-seat after opening to provide pressure relief. Due to the importance of this event, a SAMA can be developed to make PORV more reliable thereby reducing failure frequency. (SAMA 21) |
| 0HRECIRCCMY | 1.50E-01 | 1.052 | OPERATOR FAILS TO INITIATE HH RECIRC FOR SLOCA COND. ON FAILURE OF RCS COOLDOWN AND DEPRESSURIZATION | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates.<br><br>Consider installation of control logic to automatically swap to recirculation mode of ECCS, and drawing suction from RB sump prior to depletion of RWST. (SAMA 1) |
| 0PORVBLOCKY | 5.00E-02 | 1.052 | OPERATOR FAILS TO CLOSE BLOCK VALVE TO ISOLATE STUCK OPEN PORV | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates. (No specific SAMA identified) |

**Table F.5-2a**
**Unit 1 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0SLOCAXCCDY | 6.80E-02 | 1.051 | OPERATOR FAILS TO COOLDOWN AND DEPRESSURIZE RCS COND. ON FAILURE TO ISOLATE PZR PORV | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates. (No specific SAMA identified) |
| I-1-MSLBB-UP | 4.41E-04 | 1.051 | 12 SG STEAMLINE BREAK UPSTREAM OF MSIV INITIATOR FREQUENCY | This initiator identifies 12 SG steamline break initiating events and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. (No specific SAMA identified) |
| 1LVM32060XN | 3.00E-03 | 1.048 | VALVE MV-32060 FAILS TO OPEN | This valve provides suction source from RWST to charging pumps for seal injection. Local actuation of this valve could mitigate remote operation failures. However, operator recovery actions may only provide limited benefit due to the high uncertainty involved. Consider installing air operated valve in parallel to provide continuous suction source of water from RWST. (SAMA 3) |
| 1NOCONLOCA | 1.00E+00 | 1.048 | NO CONSEQUENTIAL LOCA FLAG | This event is informational and categorizes those small LOCAs that do not involve stuck open relief valves. (No specific SAMA identified) |
| 1BCC01XXCCS | 4.50E-05 | 1.043 | #11 AND #12 CC PUMPS FAIL TO START DUE TO CCF | An alternate source of water could be made available to provide the necessary cooling for RCP thermal barriers. Consider using FPS as a means to provide backup cooling source. This can be accomplished by connecting FPS directly to component cooling system header. (SAMA 12) |

**Table F.5-2a**
**Unit 1 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 0SMP11XXXYR | 9.55E-02 | 1.038 | 11 CL PUMP FAILS TO RUN (1 YEAR MISSION TIME) | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |
| 0SMP21XXXYR | 9.55E-02 | 1.038 | 21 CL PUMP FAILS TO RUN (1 YEAR MISSION TIME) | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |
| 0SPD22XXXXR | 3.91E-02 | 1.029 | 22 CL PUMP FAILS TO RUN (DIESEL DRIVER) | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. (SAMA 2) |

**Table F.5-2a**
**Unit 1 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 1HSS1211CCS | 2.99E-05 | 1.028 | #11 AND #12 SI PUMPS FAIL TO START DUE TO COMMON CAUSE | A diesel driven, HPI pump that could use a large volume, cold suction source would reduce the risk of SI pump failure. (SAMA 5) |
| 1PISGTRPROB | 5.03E-04 | 1.028 | 2-LOOP W PWR PRESSURE-INDUCED SGTR PROBABILITY | This basic event represents a phenomenological event for Level 2 accident scenarios. It is based on Westinghouse PWR analyses. (No specific SAMA identified) |
| 1V1PZRPORVF | 1.00E-01 | 1.027 | FAILURE OF PZR PORV AIR ACCUMULATOR FOLLOWING LOSS OF AIR | The station air and instrument air cross-tie has been proceduralized per IPE recommendation no. 1 (see Section F.5.1.5). Consider a portable air compressor to be used in the event of loss of air. Air compressor can be connected to air header to provide backup supply of air. (SAMA 22) |
| 1HSS1112CCR | 2.76E-05 | 1.026 | #11 AND #12 SI PUMPS FAIL TO RUN DUE TO COMMON CAUSE | A diesel driven, HPI pump that could use a large volume, cold suction source would reduce the risk of SI pump failure. (SAMA 5) |
| 1VA131231XC | 2.94E-03 | 1.026 | PORV CV-31231 FAILS TO CLOSE | This event identifies the PORV failing to re-seat after opening to provide pressure relief. Due to the importance of this event, a SAMA can be developed to make the PORV more reliable thereby reducing failure frequency. (SAMA 21) |
| 1VA131232XC | 2.94E-03 | 1.026 | PORV CV-31232 FAILS TO CLOSE | This event identifies the PORV failing to re-seat after opening to provide pressure relief. Due to the importance of this event, a SAMA can be developed to make the PORV more reliable thereby reducing failure frequency. (SAMA 21) |

**Table F.5-2b**
**Unit 2 Level 2 Importance List Review**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 2SGTRECD | 1.00E+00 | 2.29 | SGTR SEQUENCES INVOLVING EARLY CORE DAMAGE | This flag identifies the importance of SGTR sequences that involve early core damage. Component failures will be addressed elsewhere in this table. (No specific SAMA identified) |
| 0SGTRXXCD1Y | 5.00E-02 | 2.236 | OPERATOR FAILS TO COOLDOWN AND DEPRESSURIZE RCS WITH SI FAILURE FOR A SGTR | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates. (No specific SAMA identified) |
| I-2-SGTRA | 4.50E-03 | 1.392 | 21 SG STEAM GENERATOR TUBE RUPTURE INITIATING EVENT FREQ. | This initiator identifies SGTR initiating events for 21 SG and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. Consider upgrading SG to more robust design to lower accident frequency. Consider replenishing the RWST from a large source of water, such as the SFP, if failure to depressurize is part of the scenario. (SAMA 19a) |
| I-2-SGTRB | 4.50E-03 | 1.392 | 22 SG STEAM GENERATOR TUBE RUPTURE INITIATING EVENT FREQ. | This initiator identifies SGTR initiating events for 22 SG and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. Consider upgrading SG to more robust design to lower accident frequency. Consider replenishing the RWST from a large source of water, such as the SFP, if failure to depressurize is part of the scenario. (SAMA 19a) |
| 0SLOCAXXCDY | 1.90E-02 | 1.256 | OPERATOR FAILS TO PERFORM RCS COOLDOWN AND DEPRESSURIZATION ON SMALL LOCA | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates. (No specific SAMA identified) |

**Table F.5-2b**
**Unit 2 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 2NORVSTKOPN | 8.35E-01 | 1.256 | NO DEPRESSURIZATION DUE TO PORV/SRV STUCK OPEN DURING CYCLING | This event conveys information that the PORV did not fail to re-seat following pressure relief. Therefore, since there is no failure mechanism involved, no SAMA required. (No specific SAMA identified) |
| 2TISGTRPROB | 5.53E-03 | 1.236 | 2-LOOP W PWR TEMPERATURE-INDUCED SGTR PROBABILITY | This basic event represents a phenomenological event for Level 2 accident scenarios. It is based on Westinghouse PWR analyses. (No specific SAMA identified) |
| I-2-ISLOCA | 1.00E+00 | 1.225 | INTERFACING SYSTEM LOCA INITIATING EVENT FREQUENCY | This initiator identifies all interfacing system LOCA initiating events and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. (No specific SAMA identified) |
| 2BCC01XXCCS | 4.50E-05 | 1.131 | #21 AND #22 CC PUMPS FAIL TO START DUE TO CCF | An alternate source of water could be made available to provide the necessary cooling for RCP thermal barriers. Consider using FPS as a means to provide backup cooling source. This can be accomplished by connecting FPS directly to component cooling system header. (SAMA 12) |
| 0HRECIRCC2Y | 5.30E-02 | 1.124 | OPERATOR FAILS TO INITIATE HH RECIRC COND. ON FAILURE OF RCS COOLDOWN AND DEPRESSURIZATION. | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates.<br><br>Install control logic to automatically swap to recirculation mode of ECCS, and drawing suction from RB sump prior to depletion of RWST. (SAMA 1) |

**Table F.5-2b**
**Unit 2 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 2HPIPERUP | 4.00E-03 | 1.118 | CONDITIONAL PROBABILITY OF LP PIPING RUPTURE WHEN EXPOSED TO RCS PRESSURE | This basic event represents a phenomenological event for Level 2 accident scenarios. (No specific SAMA identified) |
| 2HSS2122CCS | 2.99E-05 | 1.083 | #21 AND #22 SI PUMPS FAIL TO START DUE TO COMMON CAUSE | A diesel driven, HPI pump that could use a large volume, cold suction source would reduce the risk of SI pump failure (SAMA 5). |
| I-2-SLOCAA | 1.80E-03 | 1.078 | LOOP A SMALL LOCA INITIATOR | This initiator identifies all Loop A small LOCA initiating events and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. (No specific SAMA identified) |
| I-2-SLOCAB | 1.80E-03 | 1.078 | LOOP B SMALL LOCA INITIATOR | This initiator identifies all Loop B small LOCA initiating events and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. (No specific SAMA identified) |
| 2HSS2122CCR | 2.76E-05 | 1.076 | #21 AND #22 SI PUMPS FAIL TO RUN DUE TO COMMON CAUSE | A diesel driven, HPI pump that could use a large volume, cold suction source would reduce the risk of SI pump failure (SAMA 5). |
| 2BU2TRNBXPM | 4.10E-03 | 1.05 | UNIT 2 TRAIN B CC UNAVAILABLE DUE TO PREVENTIVE MAINTENANCE | Consider deferring those PM tasks that require lengthy restoration to outage periods. For all other PM tasks, provide discreet protective barriers and signage for opposite (running) train. Online configuration risk management process most likely already takes this into account. (No specific SAMA identified) |
| 2RVH32192XL | 1.31E-04 | 1.05 | MV-32192 (LP A HL TO RHR SUCTION) CATASTROPHIC LEAK (POWER TO VALVE REMOVED) | Consider upgrading piping downstream of inboard containment isolation valve to handle RCS pressure and install outboard containment isolation valve to prevent possible ISLOCA. RHR piping downstream of newly installed valve can remain as is. (SAMA 19) |

**Table F.5-2b**
**Unit 2 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 2RVH32232XL | 1.31E-04 | 1.05 | MV-32232 (LP B HL TO RHR SUCTION) CATASTROPHIC LEAK | Consider upgrading piping downstream of inboard containment isolation valve to handle RCS pressure and install outboard containment isolation valve to prevent possible ISLOCA. RHR piping downstream of newly installed valve can remain as is. (SAMA 19) |
| 2HPI21SIXXR | 1.12E-03 | 1.048 | #21 SI PUMP FAILS TO RUN DURING HIGH HEAD INJECTION | A diesel driven, HPI pump that could use a large volume, cold suction source would reduce the risk of SI pump failure (SAMA 5).<br><br>Unit 2 SGTR frequency is higher than the frequency used for Unit 1. This appears to be driving the importance of this event. |
| 2RVM32193XL | 2.63E-03 | 1.047 | MV-32193 (LP A HL TO RHR SUCTION) FAILS TO REMAIN CLOSED | Consider upgrading piping downstream of inboard containment isolation valve to handle RCS pressure and install outboard containment isolation valve to prevent possible ISLOCA. RHR piping downstream of newly installed valve can remain as is. (SAMA 19) |
| 2RVM32233XL | 2.63E-03 | 1.047 | MV-32233 (LP B HL TO RHR SUCTION) FAILS TO REMAIN CLOSED | Consider upgrading piping downstream of inboard containment isolation valve to handle RCS pressure and install outboard containment isolation valve to prevent possible ISLOCA. RHR piping downstream of newly installed valve can remain as is. (SAMA 19) |

**Table F.5-2b**
**Unit 2 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 2HVCSI95XXL | 1.31E-03 | 1.044 | CHECK VALVE 2SI-9-5 CATASTROPHIC LEAK | This valve is in series with a second check valve (2SI-9-3), both prevent backflow from the RCS to the SI system. Both check valves are inside containment with a normally open motor-operated valve upstream (also inside containment). Consider operating with the MOV normally closed, provided that an automatic open signal is sent to the valve for injection from the RWST under a LOCA condition. (SAMA 20) |
| 2HVCSI96XXL | 1.31E-03 | 1.044 | CHECK VALVE 2SI-9-6 CATASTROPHIC INTERNAL LEAK | This valve is in series with a second check valve (2SI-9-4), both prevent backflow from the RCS to the SI system. Both check valves are inside containment with a normally open motor-operated valve upstream (also inside containment). Consider operating with the MOV normally closed, provided that an automatic open signal is sent to the valve for injection from the RWST under a LOCA condition. (SAMA 20) |
| 2PISGTRSECB | 1.00E+00 | 1.044 | PRESSURE-INDUCED SGTR PROBABILITY FOR MSLB/MFLB EVENTS WITH HIGH/DRY SG | This flag identifies pressure-induced SGTR scenarios due to high differential pressure across the SG tubes. Components related to this event will be addressed elsewhere in this table. Consider upgrading SG to more robust design to lower accident frequency. (No specific SAMA identified) |
| 2RCPSL | 1.00E+00 | 1.044 | RCP SEAL LOCA FLAG | This flag identifies the importance of all RCP seal LOCA contributors. RCP seal LOCA failures will be addressed elsewhere in this table. (No specific SAMA identified) |

**Table F.5-2b**
**Unit 2 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 2HVCSI93XXL | 1.31E-03 | 1.041 | CHECK VALVE 2SI-9-3 CATASTROPHIC LEAK | This valve is in series with a second check valve (2SI-9-5), both prevent backflow from the RCS to the SI system. Both check valves are inside containment with a normally open motor-operated valve upstream (also inside containment). Consider operating with the MOV normally closed, provided that an automatic open signal is sent to the valve for injection from the RWST under a LOCA condition. (SAMA 20) |
| 2HVCSI94XXL | 1.31E-03 | 1.041 | CHECK VALVE 2SI-9-4 CATASTROPHIC INTERNAL LEAK | This valve is in series with a second check valve (2SI-9-6), both prevent backflow from the RCS to the SI system. Both check valves are inside containment with a normally open motor-operated valve upstream (also inside containment). Consider operating with the MOV normally closed, provided that an automatic open signal is sent to the valve for injection from the RWST under a LOCA condition. (SAMA 20) |
| I-LOCL | 1.00E+00 | 1.033 | LOSS OF COOLING WATER INITIATING EVENT FREQUENCY | This event identifies all loss of cooling water scenarios that lead to CD. Due to the importance of this event, a SAMA can be developed to make use of alternate cooling water sources. (SAMA 2) |
| 2HTRAINAXPM | 1.87E-03 | 1.032 | UNIT 2 SI TRAIN A OUT FOR PREVENTIVE MAINTENANCE | Consider deferring those PM tasks that require lengthy restoration to outage periods. For all other PM tasks, provide discreet protective barriers and signage for opposite train. Online configuration risk management process most likely already takes this into account. (No specific SAMA identified) |
| 2NOCONLOCA | 1.00E+00 | 1.031 | NO CONSEQUENTIAL LOCA FLAG | This event is informational and categorizes those small LOCAs that do not involve stuck open relief valves. (No specific SAMA identified) |

**Table F.5-2b**
**Unit 2 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 2BPC21XXXXS | 6.90E-04 | 1.029 | #21 CC PUMP FAILS TO START | An alternate source of water could be made available to provide the necessary cooling for RCP thermal barriers. Consider using FPS as a means to provide backup cooling source. This can be accomplished by connecting FPS directly to component cooling system header. (SAMA 12)<br><br>Unit 2 SGTR frequency is higher than the frequency used for Unit 1. This appears to be driving the importance of this event. |
| 2PORVLOCA | 1.00E+00 | 1.028 | TRANSIENT INDUCED PORV LOCA FLAG | This flag identifies those scenarios whereby the PORV fails to re-seat after opening to provide pressure relief. Due to the importance of this event, a SAMA can be developed to make PORV more reliable thereby reducing failure frequency. (SAMA 21) |
| 0PORVBLOCKY | 5.00E-02 | 1.027 | OPERATOR FAILS TO CLOSE BLOCK VALVE TO ISOLATE STUCK OPEN PORV | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates. (No specific SAMA identified) |
| 2HPI21SIXXS | 6.46E-04 | 1.027 | #21 SI PUMP FAILS TO START DURING HIGH HEAD INJECTION | A diesel driven, HPI pump that could use a large volume, cold suction source would reduce the risk of SI pump failure (SAMA 5).<br><br>Unit 2 SGTR frequency is higher than the frequency used for Unit 1. This appears to be driving the importance of this event. |

**Table F.5-2b**
**Unit 2 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| I-2-MSLBB-UP | 4.41E-04 | 1.027 | 22 SG STEAMLINE BREAK UPSTREAM OF MSIV INITIATOR FREQUENCY | This initiator identifies 22 SG steamline break initiating events and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. (No specific SAMA identified) |
| 0SLOCAXCCDY | 6.80E-02 | 1.026 | OPERATOR FAILS TO COOLDOWN AND DEPRESSURIZE RCS COND. ON FAILURE TO ISOLATE PZR PORV | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates. (No specific SAMA identified) |
| 0HRECIRCCMY | 1.50E-01 | 1.025 | OPERATOR FAILS TO INITIATE HH RECIRC FOR SLOCA COND. ON FAILURE OF RCS COOLDOWN AND DEPRESSURIZATION | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates.<br><br>Consider installation of control logic to automatically swap to recirculation mode of ECCS, and drawing suction from RB sump prior to depletion of RWST. (SAMA 1) |
| 2LVM32062XN | 3.00E-03 | 1.024 | VALVE MV-32062 FAILS TO OPEN | This valve provides suction source from RWST to charging pumps for seal injection. Local actuation of this valve could mitigate remote operation failures. However, operator recovery actions may only provide limited benefit due to the high uncertainty involved. Consider installing air operated valve in parallel to provide continuous suction source of water from RWST. (SAMA 3) |

**Table F.5-2b**
**Unit 2 Level 2 Importance List Review (Continued)**

| Event Name | Probability | Risk Reduction Worth | Description | Potential SAMAs |
|---|---|---|---|---|
| 2HTRAINBXPM | 1.87E-03 | 1.022 | UNIT 2 TRAIN B SI OUT FOR PREVENTIVE MAINTENANCE | Consider deferring those PM tasks that require lengthy restoration to outage periods. For all other PM tasks, provide discreet protective barriers and signage for opposite train. Online configuration risk management process most likely already takes this into account. (No specific SAMA identified) |
| 0SCLLOOPBPM | 1.73E-03 | 1.021 | COOLING WATER LOOP B HEADER OUTAGE MAINTENANCE | Consider deferring those PM tasks that require lengthy restoration to outage periods. For all other PM tasks, provide discreet protective barriers and signage for opposite (running) train. Online configuration risk management process most likely already takes this into account. (No specific SAMA identified) |
| 2RSTSUMPBXF | 7.20E-03 | 1.021 | CONTAINMENT SUMP B STRAINER PLUGS DUE TO DEBRIS | Install a redundant strainer of a different design to eliminate single failure event that takes out the RHR, SI and CS systems. (SAMA 24) |
| 2BU2TRNBXCM | 1.68E-03 | 1.02 | UNIT 2 TRAIN B CC UNAVAILABLE DUE TO CORRECTIVE MAINTENANCE | Better work control practices may reduce frequency of corrective maintenance activity on the B train of CC. Consider upgrading CC pump and / or train components to a new design. (SAMA 23) |

**Table F.5-3**
**PINGP Phase I SAMA List Summary**

| SAMA Number | SAMA Title | SAMA Description | Source | Cost Estimate | Retained | Phase I Baseline Disposition |
|---|---|---|---|---|---|---|
| 1 | Recirculation automatic swap to RB sump | Install control logic to automatically swap to recirculation mode of ECCS, and drawing suction from RB sump prior to depletion of RWST. | PI Unit 1/2 Level 1 Importance List / Unit 1/2 Level 2 Importance List | $4.25M per unit ($8.5M total) (S&L 2007)<br>Breakdown:<br>Study: $278,000<br>Design:$1,695,000<br>Implement:$1,777,000<br>Life Cycle:$500,000 | No | Although not retained for Phase II, this SAMA was investigated with respect to uncertainty to gain insight on possible risk benefits at the 95$^{th}$ percentile. See Section F.7.2. |
| 2 | Alternate water source to CL system (possible 3rd Diesel CL pump train) | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. | PI Unit 1/2 Level 1 Importance List / Unit 1 Level 2 Importance List | $300K per unit ($600K total) (NMC estimate) | Yes | See Section F.6.1. |

**Table F.5-3**
**PINGP Phase I SAMA List Summary (Continued)**

| SAMA Number | SAMA Title | SAMA Description | Source | Cost Estimate | Retained | Phase I Baseline Disposition |
|---|---|---|---|---|---|---|
| 3 | Alternate flowpath from RWST | This valve provides suction source from RWST to charging pumps for seal injection. Local actuation of this valve could mitigate remote operation failures. However, operator recovery actions may only provide limited benefit due to the high uncertainty involved. Consider installing air operated valve in parallel to provide continuous suction source of water from RWST. | PI Unit 1/2 Level 1 Importance List / Unit 1/2 Level 2 Importance List | $250K per unit ($500K total) (NMC estimate) | Yes | See Section F.6.2. |
| 4 | N/A | DELETED | N/A | N/A | | |
| 5 | Diesel driven HPI pump | A diesel driven, HPI pump that could use a large volume, cold suction source would reduce the risk of LOOP & SGTR by prolonging the time the plant can operate without offsite AC power. | PI Unit 1/2 Level 1 Importance List / Unit 1/2 Level 2 Importance List | $1.5M per unit ($3M total) (NMC estimate) | Yes | See Section F.6.3. |
| 6 | EQ equipment for flooding | Consider installing waterproof (EQ) equipment (valves / level sensors) capable of automatically isolating the flooding source. | PI Unit 1 Level 1 Importance List | $400K per unit ($800K total) (NMC estimate) | No | See Section F.5.2. |

**Table F.5-3**
**PINGP Phase I SAMA List Summary (Continued)**

| SAMA Number | SAMA Title | SAMA Description | Source | Cost Estimate | Retained | Phase I Baseline Disposition |
|---|---|---|---|---|---|---|
| 6a | Segregate flooding zones | Consider segregating this zone into 2 compartments to reduce the impact of a flood on both trains of SI and RHR. | PI Unit 1 Level 1 Importance List | $2M per unit ($4M total) (NMC estimate) | No | See Section F.5.2. |
| 7 | Upgrade Diesel Generators D3 and D4 | The ability to use non-safety related diesel generators D3 and D4 would provide a backup source of power in addition to the existing four safety related diesels D1, D2, D5, and D6. | PI Unit 1/2 Level 1 Importance List | $1.2M total (NMC estimate) | No | SBO is already a small contributor - <8% of CDF, <1% of LERF, <0.02% of early CF. Top SBO-related release categories involve sequences in which containment and/or vessel does not fail. Also, significant costs would be incurred to upgrade D3 and D4 to safety-related status, which would ultimately cost more than the benefit gained from a 2% improvement in CDF. |
| 8 | Swing / SBO diesel for LOOP | Installation of a swing or SBO diesel would provide increased defense in depth and could be considered for LOOP conditions. | PI Unit 1/2 Level 1 Importance List | $8M total (NMC estimate) | No | See Section F.5.2. |

**Table F.5-3**
**PINGP Phase I SAMA List Summary (Continued)**

| SAMA Number | SAMA Title | SAMA Description | Source | Cost Estimate | Retained | Phase I Baseline Disposition |
|---|---|---|---|---|---|---|
| 9 | Analyze room heatup for natural / forced circulation | Further analysis such as room heatup calculations could be considered to determine to what extent natural or forced circulation can adequately remove heat from the affected areas, for example, portable fans, open doors, etc. | PI Unit 1/2 Level 1 Importance List | $62,500 per unit ($125K total) (S&L 2007)<br>Breakdown(Unit 1&2):<br>Study: $111,000<br>Design:none<br>Implement(procedure change):$14,000<br>Life Cycle:none | Yes | See Section F.6.4. |
| 10 | Alternate means of RWST transfer | Failure of VCT level controller disables the RWST auto transfer feature, rendering the RWST unavailable as an alternate water source to the charging pumps. Alternate means of RWST transfer could be developed, either procedurally or via plant modification. For example, an additional parallel level transmitter signal path that could prevent a spurious failure of any one signal rendering suction unavailable to the charging pumps. A 2 out of 3 level control logic would be required for auto transfer of charging pump suction. | PI Unit 1/2 Level 1 Importance List | $2.866M per unit ($5.732M total) (S&L 2007)<br>Breakdown per unit:<br>Study: $175,000<br>Design:$1,526,000<br>Implement:$865,000<br>Life Cycle:$300,000<br><br>Breakdown (Unit 2):<br>Study: $175,000<br>Design:$1,257,000<br>Implement:$865,000<br>Life Cycle:$300,000 | No | Although not retained for Phase II, this SAMA was investigated with respect to uncertainty to gain insight on possible risk benefits at the 95th percentile. See Section F.7.2. Note that addressing SAMAs 9 and/or 12 would provide much, if not most, of the benefit that might be gained from this SAMA. |
| 11 | Auto transfer logic improvements | Auto transfer logic improvements, such as improved level controller reliability could also be considered. | PI Unit 2 Level 1 Importance List | $100K per unit ($200K total) (NMC estimate) | No | See SAMA 10 above (addresses same group of sequences). |

**Table F.5-3**
**PINGP Phase I SAMA List Summary (Continued)**

| SAMA Number | SAMA Title | SAMA Description | Source | Cost Estimate | Retained | Phase I Baseline Disposition |
|---|---|---|---|---|---|---|
| 12 | Alternate RCP thermal barrier cooling | An alternate source of water could be made available to provide the necessary cooling for RCP thermal barriers. Consider using FPS as a means to provide backup cooling source. This can be accomplished by connecting FPS directly to component cooling system header. A release path will be required since FPS is not a closed system. | PI Unit 1/2 Level 1 Importance List / Unit 1/2 Level 2 Importance List | $900K per unit ($1.8M total) (NMC estimate) | Yes | See Section F.6.5. Note that SAMAs 3, 5, and 10 would address most of the CDF risk addressed by this SAMA. |
| 13 | Automatic sump pump for Zone 7 AB flooding | This initiator represents an internal flooding scenario that disables various safety-related components. Mitigation of this event can be accomplished via an automatic sump pump system to remove water if the operator fails to isolate Zone 7 of the Aux. Bldg. | PI Unit 1/2 Level 1 Importance List | $300K per unit ($600K total) (NMC estimate) | No | See Section F.5.2. |
| 14 | Operator training for PORV failure to re-seat | Reinforce operator training to isolate PORVs when symptoms reveal valves have failed to re-seat. This reduces the amount of radioactivity released to the environment. Consider replacing with more reliable or robust valves to better isolate following lifting. | PI Unit 2 Level 1 Importance List | $600K per unit ($1.2M total) (NMC estimate) | No | Existing model considers that failure to close and failure to open lead to the same accident class, GLH (assuming failure of operator to Cooldown/Depressurize per ECA 3.1/3.2, which leads to SGTR source term). Therefore, quantification of this SAMA modification would produce no difference in the calculated frequency of offsite release or its magnitude. |

**Table F.5-3**
**PINGP Phase I SAMA List Summary (Continued)**

| SAMA Number | SAMA Title | SAMA Description | Source | Cost Estimate | Retained | Phase I Baseline Disposition |
|---|---|---|---|---|---|---|
| 15 | Portable DC power source | Consider a portable DC power source, such as a rectifier or skid-mounted battery pack that could be used for restoring DC control power to vital components, such as breakers, solenoid valves, etc. | PI Unit 2 Level 1 Importance List | $130K per unit ($260K total) (NMC estimate) | Yes | See Section F.6.6. |
| 16 | Replace RHR Loop B return valve | Failure of MV-32169 to open disables RHR Loop B return. Proper operation of this valve is most likely tracked via the MR. Consider replacing this MOV with a FC air-operated valve for improved reliability. This would eliminate CCF for inboard MOVs that currently exist on this flowpath. | PI Unit 2 Level 1 Importance List | $1.2M per unit ($2.4M total) (NMC estimate) | No | Failure of this valve to open results in failure of shutdown cooling initiation (there is no CCF for inboard MOVs that currently exist for the flowpath involved in these sequences). This may not have any positive impact on CDF (FC air-operated valve inside containment may be less reliable than a MOV due to reliance on containment instrument air supply) and would have little, if any, impact on LERF. |
| 17 | Bypass around RHR Loop B return valves | Alternatively, a bypass flowpath could be installed around inboard RHR Loop B return valves for improved defense in depth. | PI Unit 2 Level 1 Importance List | $2.362M per unit ($4.724M total) (S&L 2007) Breakdown: Study: $112,000 Design:$870,000 Implement:$1,080,000 Life Cycle:$300,000 | No | Although not retained for Phase II, this SAMA was investigated with respect to uncertainty to gain insight on possible risk benefits at the 95th percentile. See Section F.7.2. |

**Table F.5-3**
**PINGP Phase I SAMA List Summary (Continued)**

| SAMA Number | SAMA Title | SAMA Description | Source | Cost Estimate | Retained | Phase I Baseline Disposition |
|---|---|---|---|---|---|---|
| 18 | Install spare TDAFW for each unit | Operator training can be emphasized to reduce human error probability; however, there is a great deal of uncertainty regarding operator failure probability estimates. Consider installing a spare turbine-driven AFW pump per unit. This would increase reliability of AFW system for each unit. The new pumps would be dedicated to the corresponding unit with no cross-tie capability, thereby eliminating operator error for this action. Note - some operating PWRs have (3) AFW pumps per unit, which provide greater redundancy and defense in depth. | PI Unit 2 Level 1 Importance List | $4M per unit ($8M total) (NMC estimate) | No | TDAFWP makes U2 CDF list only - this is due to Train A DC dependency between Train A AFW and MFW that Unit 1 does not have. Would reduce CDF but would do little for LERF. Implementation of SAMA 15 would reduce the importance of this item and would involve significantly less cost. |
| 19 | Upgrade RHR suction piping / install cont. isol. valve | For Loop A/B HL return to RHR suction, consider upgrading piping downstream of inboard containment isolation valve to handle RCS pressure and install outboard containment isolation valve to prevent possible ISLOCA. RHR piping downstream of newly installed valve can remain as is. | PI Unit 1/2 Level 2 Importance List | $700K per unit ($1.4M total) (NMC estimate) | Yes | See Section F.6.7. |

**Table F.5-3**
**PINGP Phase I SAMA List Summary (Continued)**

| SAMA Number | SAMA Title | SAMA Description | Source | Cost Estimate | Retained | Phase I Baseline Disposition |
|---|---|---|---|---|---|---|
| 19a | Replenish RWST from large water source | This initiator identifies SGTR initiating events for 11 / 12 SG and is based on industry data. Therefore mitigative actions will be addressed elsewhere in this table. Consider upgrading SG to more robust design to lower accident frequency. Consider replenishing the RWST from a large source of water, such as the SFP, if failure to depressurize is part of the scenario | PI Unit 2 Level 1 and Unit 1/2 Level 2 Importance Lists | $1.935M per unit ($3.87M total) (S&L 2007) Breakdown: Study: $225,000 Design:$1,851,000 Implement:$1,294,000 Life Cycle:$500,000 | No | Although not retained for Phase II, this SAMA was investigated with respect to uncertainty to gain insight on possible risk benefits at the 95$^{th}$ percentile. See Section F.7.2. |
| 20 | Close MOV to prevent RCS backflow to SI system | This check valve is in series with a second check valve, both prevent backflow from the RCS to the SI system. Both check valves are inside containment with a normally open motor-operated valve upstream (also inside containment). Consider operating with the MOV normally closed, provided that an automatic open signal is sent to the valve for injection from the RWST under a LOCA condition. | PI Unit 1/2 Level 2 Importance List | $313K per unit ($626K total) (S&L 2007) Breakdown: Study: $52,000 Design:$105,000 Implement:$56,000 Life Cycle:$100,000 | Yes | See Section F.6.8. |
| 21 | Increase reliability of PORV to re-seat | This event identifies the PORV failing to re-seat after opening to provide pressure relief. Due to the importance of this event, a SAMA can be developed to make the PORV more reliable thereby reducing failure frequency. | PI Unit 1/2 Level 2 Importance List | $3M per unit ($6M total) (NMC estimate) | No | Although not retained for Phase II, this SAMA was investigated with respect to uncertainty to gain insight on possible risk benefits at the 95$^{th}$ percentile. See Section F.7.2. |

**Table F.5-3**
**PINGP Phase I SAMA List Summary (Continued)**

| SAMA Number | SAMA Title | SAMA Description | Source | Cost Estimate | Retained | Phase I Baseline Disposition |
|---|---|---|---|---|---|---|
| 22 | Portable air compressor for containment instrument air supply backup, or tie into (and make available during at power operation) air supply for LTOP used during outages | Consider a portable air compressor to be used in the event of loss of air to RCS PORVs inside containment. Air compressor can be connected to air header inside containment to provide backup supply of air. An alternative would be to tie into nitrogen (or air) bottle source that supplies air to LTOP system during outages. | PI Unit 1 Level 2 Importance List / IPE | $39K per unit ($78K total) (S&L 2007) Breakdown: Study: $39,000 Design: None Implement: None Life Cycle: None | Yes | See Section F.6.9. |

**Table F.5-3**
**PINGP Phase I SAMA List Summary (Continued)**

| SAMA Number | SAMA Title | SAMA Description | Source | Cost Estimate | Retained | Phase I Baseline Disposition |
|---|---|---|---|---|---|---|
| 23 | Better work control / upgrade CC pump / train | Better work control practices may reduce frequency of corrective maintenance activity on the B train of CC. Consider upgrading CC pump and / or train components to a new design. | PI Unit 2 Level 2 Importance List | $2.5M per unit ($5M total) (NMC estimate) | No | U2 LERF risk from Tr. B CCW is from SGTR initiating event - SI pump requires CC for continued operation. Not as significant on U1 due to lower SGTR IE frequency from SG replacement. This event is very close to the screening threshold (RRW = 1.02), and would be an expensive modification. SAMA #5 and 19a will address this risk contributor in the interim until planned SG replacement on U2 (2013). Note: Maximum benefit from improved work control practices has probably already been achieved as CCW corrective maintenance impacts MSPI and MR performance indicators (management is highly aware of the need to minimize CM on CCW). |

**Table F.5-3**
**PINGP Phase I SAMA List Summary (Continued)**

| SAMA Number | SAMA Title | SAMA Description | Source | Cost Estimate | Retained | Phase I Baseline Disposition |
|---|---|---|---|---|---|---|
| 24 | Install redundant RB sump strainer | Install a redundant strainer of a different design to eliminate single failure event that takes out the RHR, SI and CS systems. | PI Unit 2 Level 2 Importance List | $1.2M per unit ($2.4M total) (NMC estimate) | No | This would be an expensive modification to perform directly after current modifications to sump strainers to meet the G.L. Treatment of post accident sump strainer reliability in PRA is currently subject of significant industry/NRC attention and modeling is likely to be changed when consensus is reached on a methodology. Until then, SAMAs 16 or 17, 21, and 22 address part of the LERF risk from sump strainer blockage. See sensitivity study in Section F.2.2.2. |

**Table F.6-1**
**PINGP Phase II SAMA List Summary**

| SAMA Number | SAMA Title | SAMA Description | Source | Phase II Baseline Disposition |
|---|---|---|---|---|
| 2 | Alternate water source to CL system | Failure of the cooling water system / pumps may be mitigated via an alternate source of water. The Fire Protection System (FPS) is a standby pressurized water supply that can be connected to the main header of the cooling water system. Multiple connections from FPS to the cooling water system would result in increased defense in depth. The FPS is assumed not to be subject to the same type of failures as the cooling water system, such as screenhouse ventilation failures. | PI Unit 1/2 Level 1 Importance List / Unit 1 Level 2 Importance List | The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is <u>not</u> cost beneficial. |
| 3 | Alternate flowpath from RWST | This valve provides suction source from RWST to charging pumps for seal injection. Local actuation of this valve could mitigate remote operation failures. Since operator recovery actions may only provide limited benefit due to the high uncertainty involved, consider installing air operated valve in parallel to provide continuous suction source of water from RWST. | PI Unit 1/2 Level 1 Importance List / Unit 1/2 Level 2 Importance List | The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is <u>not</u> cost beneficial. |
| 5 | Diesel driven HPI pump | A diesel driven, HPI pump that could use a large volume, cold suction source would reduce the risk of LOOP & SGTR by prolonging the time the plant can operate without offsite AC power. | PI Unit 1/2 Level 1 Importance List / Unit 1/2 Level 2 Importance List | The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is <u>not</u> cost beneficial. |
| 9 | Analyze room heatup for natural / forced circulation | Further analysis such as room heatup calculations could be considered to determine to what extent natural or forced circulation can adequately remove heat from the affected areas, for example, portable fans, open doors, etc. | PI Unit 1/2 Level 1 Importance List | The averted cost-risk for this SAMA is **greater** than the cost of implementation and the SAMA is **cost beneficial** (based on 95$^{th}$ percentile results). |

**Table F.6-1**
**PINGP Phase II SAMA List Summary (Continued)**

| SAMA Number | SAMA Title | SAMA Description | Source | Phase II Baseline Disposition |
|---|---|---|---|---|
| 12 | Alternate RCP thermal barrier cooling | An alternate source of water could be made available to provide the necessary cooling for RCP thermal barriers. Consider using FPS as a means to provide backup cooling source. This can be accomplished by connecting FPS directly to component cooling system header. A release path will be required since FPS is not a closed system. | PI Unit 1/2 Level 1 Importance List / Unit 1/2 Level 2 Importance List | The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is <u>not</u> cost beneficial. |
| 15 | Portable DC power source | Consider a portable DC power source, such as a rectifier or skid-mounted battery pack that could be used for restoring DC control power to vital components, such as breakers, solenoid valves, etc. | PI Unit 2 Level 1 Importance List | The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is <u>not</u> cost beneficial. |
| 19 | Upgrade RHR suction piping / install cont. isol. valve | For Loop A/B HL return to RHR suction, consider upgrading piping downstream of inboard containment isolation valve to handle RCS pressure and install outboard containment isolation valve to prevent possible ISLOCA. RHR piping downstream of newly installed valve can remain as is. | PI Unit 1/2 Level 2 Importance List | The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is <u>not</u> cost beneficial. |
| 20 | Close MOV to prevent RCS backflow to SI system | This check valve is in series with a second check valve, both prevent backflow from the RCS to the SI system. Both check valves are inside containment with a normally open motor-operated valve upstream (also inside containment). Consider operating with the MOV normally closed, provided that an automatic open signal is sent to the valve for injection from the RWST under a LOCA condition. | PI Unit 1/2 Level 2 Importance List | The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is <u>not</u> cost beneficial. |

**Table F.6-1**
**PINGP Phase II SAMA List Summary (Continued)**

| SAMA Number | SAMA Title | SAMA Description | Source | Phase II Baseline Disposition |
|---|---|---|---|---|
| 22 | Portable air compressor for containment instrument air supply backup, or tie into (and make available during at power operation) air supply for LTOP used during outages | Instead of a plant hardware modification, the low cost option of analyzing the actual capability of the backup air accumulators was chosen to more realistically show that operation of the PORV can successfully provide bleed and feed cooling when secondary side heat removal via the SGs is unavailable. This would involve a review of any overly conservative assumptions found from previous analyses. | PI Unit 1 Level 2 Importance List / IPE | The averted cost-risk for this SAMA is **greater** than the cost of implementation and the SAMA is **cost beneficial** (based on 95$^{th}$ percentile results). |

## F.10 FIGURES

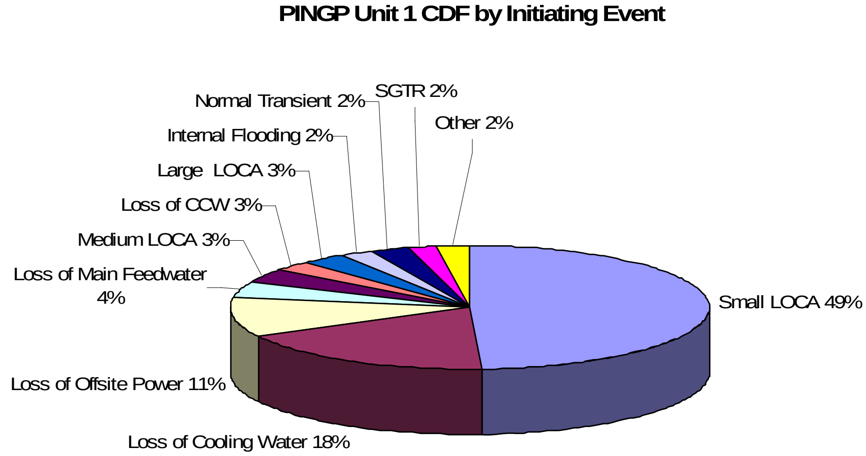



**Figure F.2-1**
**Contribution to Unit 1 CDF by Initiator**

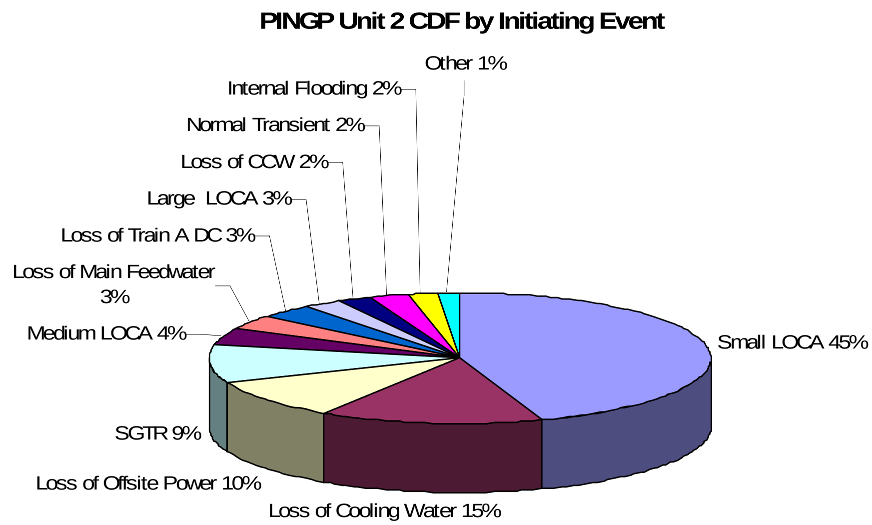



**Figure F.2-2**
**Contribution to Unit 2 CDF by Initiator**

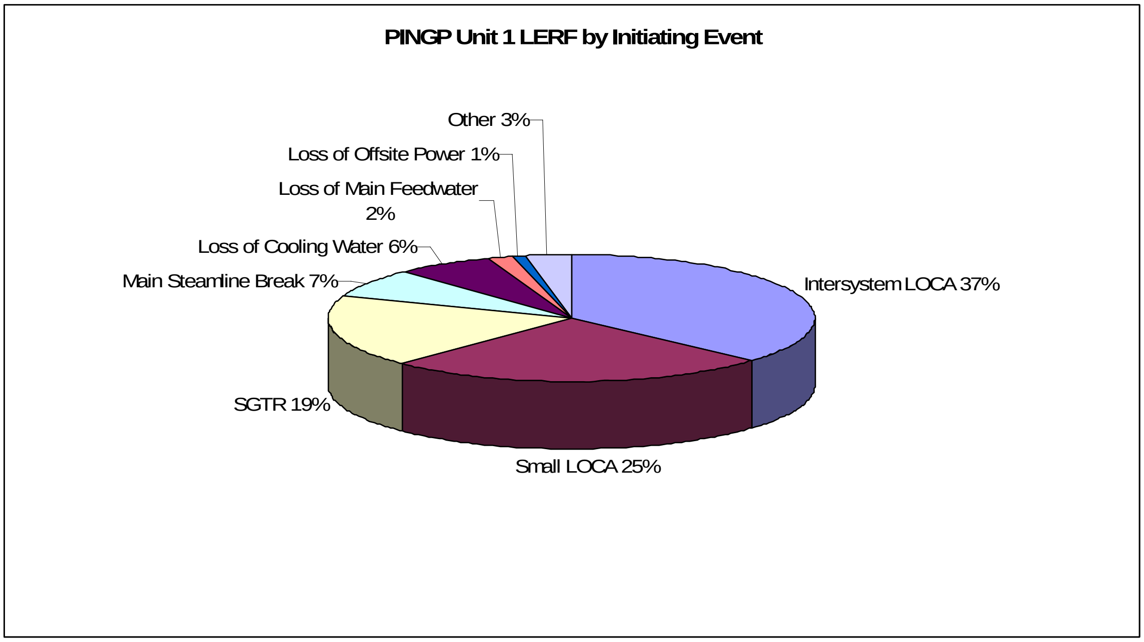



**Figure F.2-3**
**Contribution to Unit 1 LERF by Initiator**

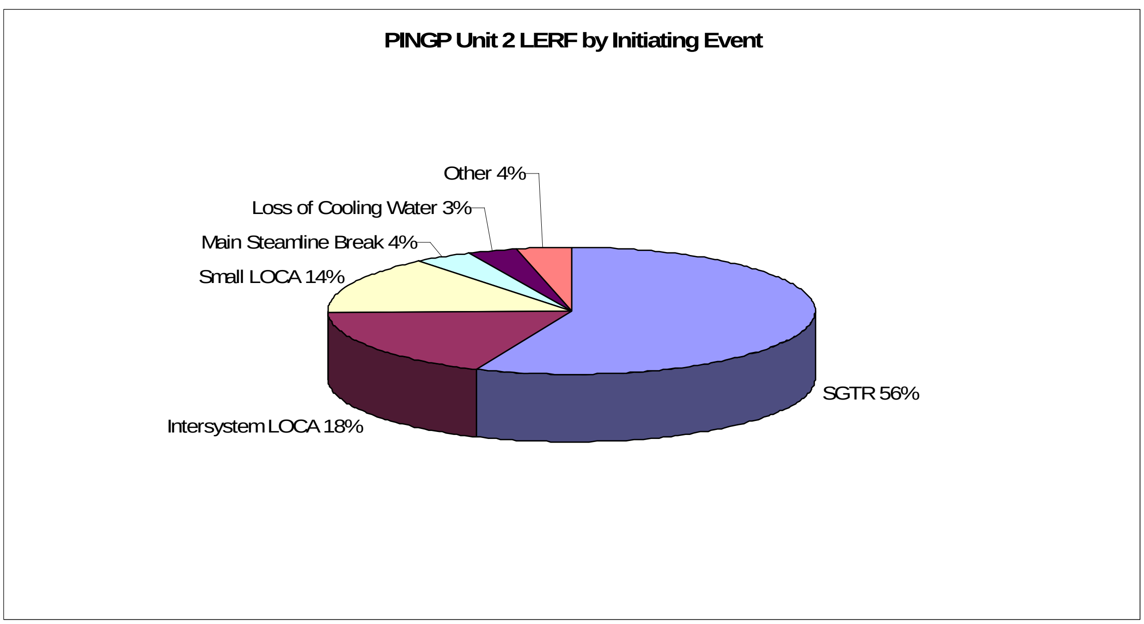



**Figure F.2-4**
**Contribution to Unit 2 LERF by Initiator**

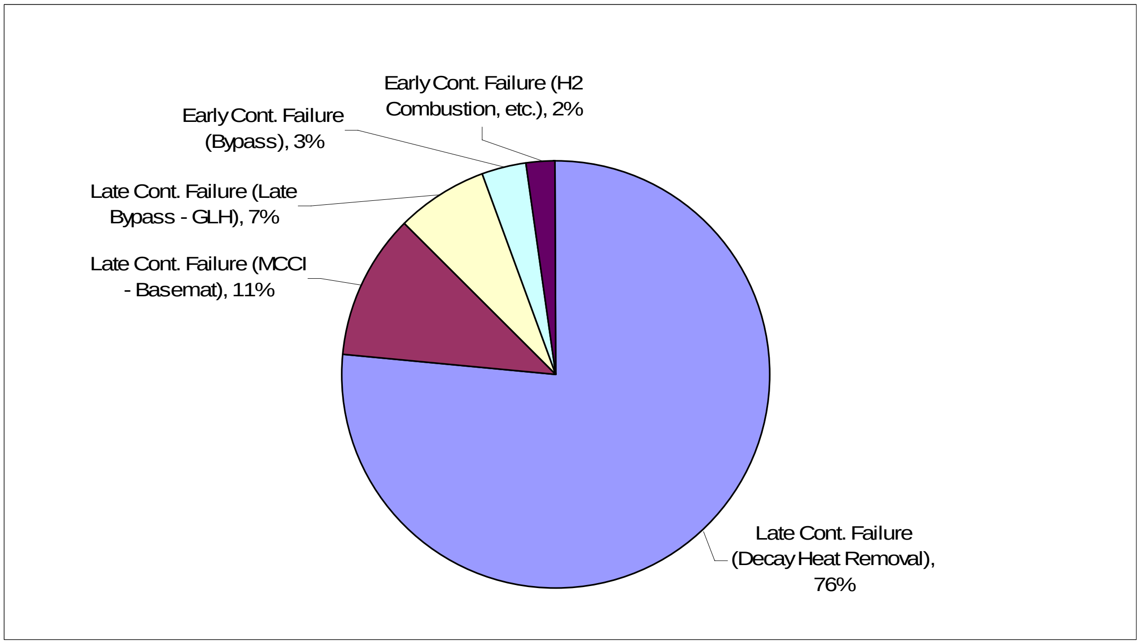



**Figure F.2-5**
**Unit 1 Containment Failure Modes**

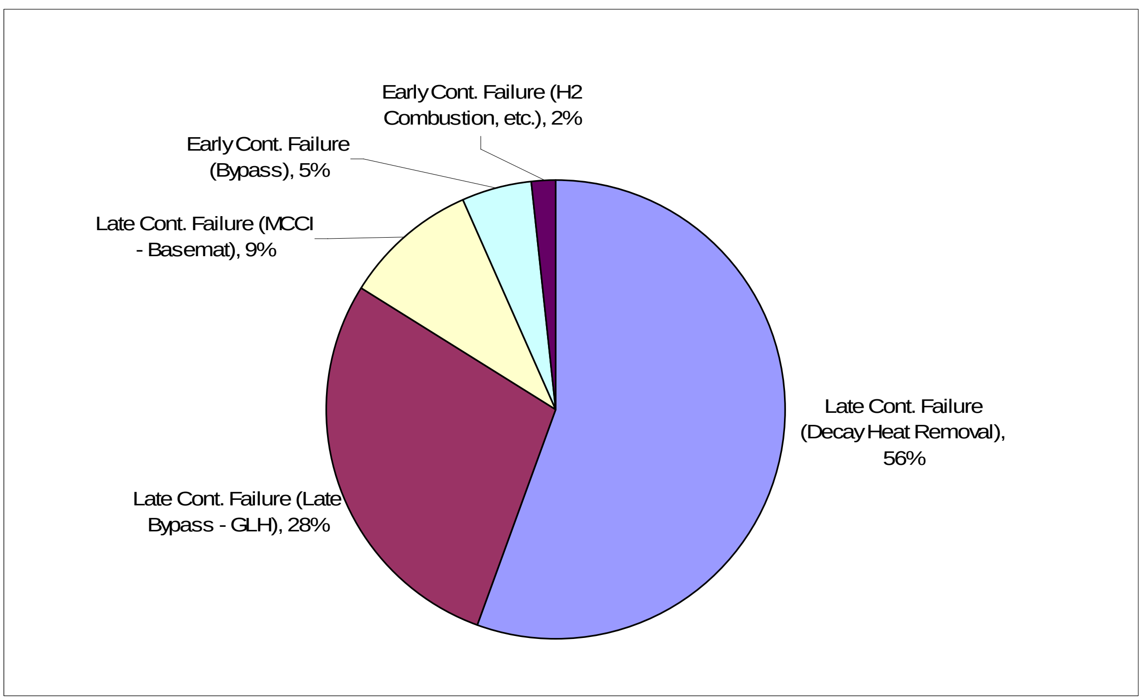



**Figure F.2-6**
**Unit 2 Containment Failure Modes**

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## Addendum 1 Selected Previous Industry SAMAs

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| | **Improvements Related to RCP Seal LOCAs (Loss of CC or SW)** | |
| 1 | Cap downstream piping of normally closed component cooling water drain and vent valves. | SAMA would reduce the frequency of a loss of component cooling event, a large portion of which was derived from catastrophic failure of one of the many single isolation valves. |
| 2 | Enhance loss of component cooling procedure to facilitate stopping reactor coolant pumps. | SAMA would reduce the potential for reactor coolant pump (RCP) seal damage due to pump bearing failure. |
| 3 | Enhance loss of component cooling procedure to present desirability of cooling down reactor coolant system (RCS) prior to seal LOCA. | SAMA would reduce the potential for RCP seal failure. |
| 4 | Provide additional training on the loss of component cooling. | SAMA would potentially improve the success rate of operator actions after a loss of component cooling (to restore RCP seal damage). |
| 5 | Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals. | SAMA would reduce effect of loss of component cooling by providing a means to maintain the centrifugal charging pump seal injection after a loss of component cooling. |
| 6 | Procedure changes to allow cross connection of motor cooling for RHRSW pumps. | SAMA would allow continued operation of both RHRSW pumps on a failure of one train of PSW. |
| 7 | Proceduralize shedding component cooling water loads to extend component cooling heatup on loss of essential raw cooling water. | SAMA would increase time before the loss of component cooling (and reactor coolant pump seal failure) in the loss of essential raw cooling water sequences. |
| 8 | Increase charging pump lube oil capacity. | SAMA would lengthen the time before centrifugal charging pump failure due to lube oil overheating in loss of CC sequences. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 9 | Eliminate the RCP thermal barrier dependence on component cooling such that loss of component cooling does not result directly in core damage. | SAMA would prevent the loss of recirculation pump seal integrity after a loss of component cooling. Watts Bar Nuclear Plant IPE said that they could do this with essential raw cooling water connection to RCP seals. |
| 10 | Add redundant DC control power for PSW pumps C & D. | SAMA would increase reliability of PSW and decrease core damage frequency due to a loss of SW. |
| 11 | Create an independent RCP seal injection system, with a dedicated diesel. | SAMA would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of component cooling or service water or from a station blackout event. |
| 12 | Use existing hydro-test pump for RCP seal injection. | SAMA would provide an independent seal injection source, without the cost of a new system. |
| 13 | Replace ECCS pump motor with air-cooled motors. | SAMA would eliminate ECCS dependency on component cooling system (but not on room cooling). |
| 14 | Install improved RCS pumps seals. | SAMA would reduce probability of RCP seal LOCA by installing RCP seal O-ring constructed of improved materials |
| 15 | Install additional component cooling water pump. | SAMA would reduce probability of loss of component cooling leading to RCP seal LOCA. |
| 16 | Prevent centrifugal charging pump flow diversion from the relief valves. | SAMA modification would reduce the frequency of the loss of RCP seal cooling if relief valve opening causes a flow diversion large enough to prevent RCP seal injection. |
| 17 | Change procedures to isolate RCP seal letdown flow on loss of component cooling, and guidance on loss of injection during seal LOCA. | SAMA would reduce CDF from loss of seal cooling. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 18 | Implement procedures to stagger high pressure safety injection (HPSI) pump use after a loss of service water. | SAMA would allow HPSI to be extended after a loss of service water. |
| 19 | Use FP system pumps as a backup seal injection and high pressure makeup. | SAMA would reduce the frequency of the RCP seal LOCA and the SBO CDF. |
| 20 | Enhance procedural guidance for use of cross-tied component cooling or service water pumps. | SAMA would reduce the frequency of the loss of component cooling water and service water. |
| 21 | Procedure enhancements and operator training in support system failure sequences, with emphasis on anticipating problems and coping. | SAMA would potentially improve the success rate of operator actions subsequent to support system failures. |
| 22 | Improved ability to cool the residual heat removal heat exchangers. | SAMA would reduce the probability of a loss of decay heat removal by implementing procedure and hardware modifications to allow manual alignment of the FP system or by installing a component cooling water cross-tie. |
| 23 | 8.a. Additional Service Water Pump | SAMA would conceivably reduce common cause dependencies from SW system and thus reduce plant risk through system reliability improvement. |
| 24 | Create an independent RCP seal injection system, without dedicated diesel | This SAMA would add redundancy to RCP seal cooling alternatives, reducing the CDF from loss of CC or SW, but not SBO. |
| | **Improvements Related to Heating, Ventilation, and Air Conditioning** | |
| 25 | Provide reliable power to control building fans. | SAMA would increase availability of control room ventilation on a loss of power. |
| 26 | Provide a redundant train of ventilation. | SAMA would increase the availability of components dependent on room cooling. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 27 | Procedures for actions on loss of HVAC. | SAMA would provide for improved credit to be taken for loss of HVAC sequences (improved affected electrical equipment reliability upon a loss of control building HVAC). |
| 28 | Add a diesel building switchgear room high temperature alarm. | SAMA would improve diagnosis of a loss of switchgear room HVAC.<br>Option 1: Install high temp alarm.<br>Option 2: Redundant louver and thermostat |
| 29 | Create ability to switch fan power supply to DC in an SBO event. | SAMA would allow continued operation in an SBO event. This SAMA was created for reactor core isolation cooling system room at Fitzpatrick Nuclear Power Plant. |
| 30 | Enhance procedure to instruct operators to trip unneeded RHR/CS pumps on loss of room ventilation. | SAMA increases availability of required RHR/CS pumps. Reduction in room heat load allows continued operation of required RHR/CS pumps, when room cooling is lost. |
| 31 | Stage backup fans in switchgear (SWGR) rooms | This SAMA would provide alternate ventilation in the event of a loss of SWGR Room ventilation |
| | **Improvements Related to Ex-Vessel Accident Mitigation/Containment Phenomena** | |
| 32 | Delay containment spray actuation after large LOCA. | SAMA would lengthen time of RWST availability. |
| 33 | Install containment spray pump header automatic throttle valves. | SAMA would extend the time over which water remains in the RWST, when full Containment Spray flow is not needed |
| 34 | Install an independent method of suppression pool cooling (BWR only). | SAMA would decrease the probability of loss of containment heat removal. For PWRs, a potential similar enhancement would be to install an independent cooling system for sump water. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 35 | Develop an enhanced drywell / containment spray system. | SAMA would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal. |
| 36 | Provide dedicated existing drywell / containment spray system. | SAMA would provide a source of water to the containment to control containment pressure, when used in conjunction with containment heat removal. This would use an existing spray loop instead of developing a new spray system. |
| 37 | Install an unfiltered hardened containment vent. | SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products not being scrubbed. |
| 38 | Install a filtered containment vent to remove decay heat. | SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products being scrubbed.<br>Option 1: Gravel Bed Filter<br>Option 2: Multiple Venturi Scrubber |
| 39 | Install a containment vent large enough to remove ATWS decay heat. | Assuming that injection is available, this SAMA would provide alternate decay heat removal in an ATWS event. |
| 40 | Create/enhance hydrogen recombiners with independent power supply. | SAMA would reduce hydrogen detonation at lower cost, Use either<br>1) a new independent power supply<br>2) a nonsafety-grade portable generator<br>3) existing station batteries<br>4) existing AC/DC independent power supplies. |
| 41 | Install hydrogen recombiners. | SAMA would provide a means to reduce the chance of hydrogen detonation. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 42 | Create a passive design hydrogen ignition system. | SAMA would reduce hydrogen denotation system without requiring electric power. |
| 43 | Create a large concrete crucible with heat removal potential under the basemat to contain molten core debris. | SAMA would ensure that molten core debris escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a melt-through of the basemat. |
| 44 | Create a water-cooled rubble bed on the pedestal. | SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled. |
| 45 | Provide modification for flooding the drywell head (BWR only). | SAMA would help mitigate accidents that result in the leakage through the drywell head seal. |
| 46 | Enhance FP system and/or standby gas treatment system (BWR only) hardware and procedures. | SAMA would improve fission product scrubbing in severe accidents. |
| 47 | Create a reactor cavity flooding system. | SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing. |
| 48 | Create other options for reactor cavity flooding. | SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing. |
| 49 | Enhance air return fans (ice condenser plants). | SAMA would provide an independent power supply for the air return fans, reducing containment failure in SBO sequences. |
| 50 | Create a core melt source reduction system. | SAMA would provide cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal form the vitrified compound would be facilitated, and concrete attack would not occur |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 51 | Provide a containment inerting capability. | SAMA would prevent combustion of hydrogen and carbon monoxide gases. |
| 52 | Use the FP system as a backup source for the containment spray system. | SAMA would provide redundant containment spray function without the cost of installing a new system. |
| 53 | Install a secondary containment filtered vent (BWR only). | SAMA would filter fission products released from primary containment. |
| 54 | Install a passive containment spray system. | SAMA would provide redundant containment spray method without high cost. |
| 55 | Strengthen primary/secondary containment (BWR only). | SAMA would reduce the probability of containment overpressurization to failure. |
| 56 | Increase the depth of the concrete basemat or use an alternative concrete material to ensure melt-through does not occur. | SAMA would prevent basemat melt-through. |
| 57 | Provide a reactor vessel exterior cooling system. | SAMA would provide the potential to cool a molten core before it causes vessel failure, if the lower head could be submerged in water. |
| 58 | Construct a building to be connected to primary/secondary containment that is maintained at a vacuum (BWR only). | SAMA would provide a method to depressurize containment and reduce fission product release. |
| 59 | Refill CST | SAMA would reduce the risk of core damage during events such as extended station blackouts or LOCAs which render the suppression pool unavailable as an injection source due to heat up. |
| 60 | Maintain ECCS suction on CST | SAMA would maintain suction on the CST as long as possible to avoid pump failure as a result of high suppression pool temperature |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 61 | Modify containment flooding procedure to restrict flooding to below Top of Active Fuel | SAMA would avoid forcing containment venting |
| 62 | Enhance containment venting procedures with respect to timing, path selection and technique. | SAMA would improve likelihood of successful venting strategies. |
| 63 | 1.a. Severe Accident EPGs/Accident Management Guidelines | SAMA would lead to improved arrest of core melt progress and prevention of containment failure |
| 64 | 1.h. Simulator Training for Severe Accident | SAMA would lead to improved arrest of core melt progress and prevention of containment failure |
| 65 | 2.g. Dedicated Suppression Pool Cooling (BWR only) | SAMA would decrease the probability of loss of containment heat removal.<br><br>While PWRs do not have suppression pools, a similar modification may be applied to the sump. Installation of a dedicated sump cooling system would provide an alternate method of cooling injection water. |
| 66 | 3.a. Larger Volume Containment | SAMA increases time before containment failure and increases time for recovery |
| 67 | 3.b. Increased Containment Pressure Capability (sufficient pressure to withstand severe accidents) | SAMA minimizes likelihood of large releases |
| 68 | 3.c. Improved Vacuum Breakers (redundant valves in each line) (BWR only) | SAMA reduces the probability of a stuck open vacuum breaker. |
| 69 | 3.d. Increased Temperature Margin for Seals (BWR only) | This SAMA would reduce containment failure due to drywell head seal failure caused by elevated temperature and pressure. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 70 | 3.e. Improved Leak Detection | This SAMA would help prevent LOCA events by identifying pipes which have begun to leak. These pipes can be replaced before they break. |
| 71 | 3.f. Suppression Pool Scrubbing (BWR only) | Directing releases through the suppression pool will reduce the radionuclides allowed to escape to the environment. |
| 72 | 3.g. Improved Bottom Penetration Design | SAMA reduces failure likelihood of RPV bottom head penetrations |
| 73 | 4.a. Larger Volume Suppression Pool (double effective liquid volume) (BWR only) | SAMA would increase the size of the suppression pool so that heatup rate is reduced, allowing more time for recovery of a heat removal system |
| 74 | 5.a/d. Unfiltered Vent | SAMA would provide an alternate decay heat removal method with the released fission products not being scrubbed. |
| 75 | 5.b/c. Filtered Vent | SAMA would provide an alternate decay heat removal method with the released fission products being scrubbed. |
| 76 | 6.a. Post Accident Inerting System | SAMA would reduce likelihood of gas combustion inside containment |
| 77 | 6.b. Hydrogen Control by Venting | Prevents hydrogen detonation by venting the containment before combustible levels are reached. |
| 78 | 6.c. Pre-inerting | SAMA would reduce likelihood of gas combustion inside containment |
| 79 | 6.d. Ignition Systems | Burning combustible gases before they reach a level which could cause a harmful detonation is a method of preventing containment failure. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 80 | 6.e. Fire Suppression System Inerting (BWR only) | Use of the FP system as a back up containment inerting system would reduce the probability of combustible gas accumulation. This would reduce the containment failure probability for small containments (e.g. BWR MKI). |
| 81 | 7.a. Drywell Head Flooding (BWR only) | SAMA would provide intentional flooding of the upper drywell head such that if high drywell temperatures occurred, the drywell head seal would not fail. |
| 82 | 7.b. Containment Spray Augmentation | This SAMA would provide additional means of providing flow to the containment spray system. |
| 83 | 12.b. Integral Basemat | This SAMA would improve containment and system survivability for seismic events. |
| 84 | 13.a. Reactor Building Sprays (BWR only) | This SAMA provides the capability to use firewater sprays in the reactor building to mitigate release of fission products into the Rx Bldg following an accident. |
| 85 | 14.a. Flooded Rubble Bed | SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled. |
| 86 | 14.b. Reactor Cavity Flooder | SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing. |
| 87 | 14.c. Basaltic Cements | SAMA minimizes carbon dioxide production during core concrete interaction. |
| 88 | Provide a core debris control system | (Intended for ice condenser plants): This SAMA would prevent the direct core debris attack of the primary containment steel shell by erecting a barrier between the seal table and the containment shell. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 89 | Add ribbing to the containment shell | This SAMA would reduce the risk of buckling of containment under reverse pressure loading. |
| | **Improvements Related to Enhanced AC/DC Reliability/Availability** | |
| 90 | Proceduralize alignment of spare diesel to shutdown board after loss of offsite power and failure of the diesel normally supplying it. | SAMA would reduce the SBO frequency. |
| 91 | Provide an additional diesel generator. | SAMA would increase the reliability and availability of onsite emergency AC power sources. |
| 92 | Provide additional DC battery capacity. | SAMA would ensure longer battery capability during an SBO, reducing the frequency of long-term SBO sequences. |
| 93 | Use fuel cells instead of lead-acid batteries. | SAMA would extend DC power availability in an SBO. |
| 94 | Procedure to cross-tie high pressure core spray diesel (BWR only). | SAMA would improve core injection availability by providing a more reliable power supply for the high pressure core spray pumps. |
| 95 | Improve 4.16-kV bus cross-tie ability. | SAMA would improve AC power reliability. |
| 96 | Incorporate an alternate battery charging capability. | SAMA would improve DC power reliability by either cross-tying the AC busses, or installing a portable diesel-driven battery charger. |
| 97 | Increase/improve DC bus load shedding. | SAMA would extend battery life in an SBO event. |
| 98 | Replace existing batteries with more reliable ones. | SAMA would improve DC power reliability and thus increase available SBO recovery time. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 99 | Mod for DC Bus A reliability (BWR only). | SAMA would increase the reliability of AC power and injection capability. Loss of DC Bus A causes a loss of main condenser prevents transfer from the main transformer to offsite power, and defeats one half of the low vessel pressure permissive for LPCI/CS injection valves. |
| 100 | Create AC power cross-tie capability with other unit. | SAMA would improve AC power reliability. |
| 101 | Create a cross-tie for diesel fuel oil. | SAMA would increase diesel fuel oil supply and thus diesel generator, reliability. |
| 102 | Develop procedures to repair or replace failed 4-kV breakers. | SAMA would offer a recovery path from a failure of the breakers that perform transfer of 4.16-kV non-emergency busses from unit station service transformers, leading to loss of emergency AC power. |
| 103 | Emphasize steps in recovery of offsite power after an SBO. | SAMA would reduce human error probability during offsite power recovery. |
| 104 | Develop a severe weather conditions procedure. | For plants that do not already have one, this SAMA would reduce the CDF for external weather-related events. |
| 105 | Develop procedures for replenishing diesel fuel oil. | SAMA would allow for long-term diesel operation. |
| 106 | Install gas turbine generator. | SAMA would improve onsite AC power reliability by providing a redundant and diverse emergency power system. |
| 107 | Create a backup source for diesel cooling. (Not from existing system) | This SAMA would provide a redundant and diverse source of cooling for the diesel generators, which would contribute to enhanced diesel reliability. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 108 | Use FP system as a backup source for diesel cooling. | This SAMA would provide a redundant and diverse source of cooling for the diesel generators, which would contribute to enhanced diesel reliability. |
| 109 | Provide a connection to an alternate source of offsite power. | SAMA would reduce the probability of a loss of offsite power event. |
| 110 | Bury offsite power lines. | SAMA could improve offsite power reliability, particularly during severe weather. |
| 111 | Replace anchor bolts on diesel generator oil cooler. | Millstone Nuclear Power Station found a high seismic SBO risk due to failure of the diesel oil cooler anchor bolts. For plants with a similar problem, this would reduce seismic risk. Note that these were Fairbanks Morse DGs. |
| 112 | Change undervoltage (UV), auxiliary feedwater actuation signal (AFAS) block and high pressurizer pressure actuation signals to 3-out-of-4, instead of 2-out-of-4 logic. | SAMA would reduce risk of 2/4 inverter failure. |
| 113 | Provide DC power to the 120/240-V vital AC system from the Class 1E station service battery system instead of its own battery. | SAMA would increase the reliability of the 120-VAC Bus. |
| 114 | Bypass Diesel Generator Trips | SAMA would allow D/Gs to operate for longer. |
| 115 | 2.i. 16 hour Station Blackout Injection | SAMA includes improved capability to cope with longer station blackout scenarios. |
| 116 | 9.a. Steam Driven Turbine Generator (BWR only) | This SAMA would provide a steam driven turbine generator which uses reactor steam and exhausts to the suppression pool. If large enough, it could provide power to additional equipment. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 117 | 9.b. Alternate Pump Power Source | This SAMA would provide a small dedicated power source such as a dedicated diesel or gas turbine for the feedwater or condensate pumps, so that they do not rely on offsite power. |
| 118 | 9.d. Additional Diesel Generator | SAMA would reduce the SBO frequency. |
| 119 | 9.e. Increased Electrical Divisions | SAMA would provide increased reliability of AC power system to reduce core damage and release frequencies. |
| 120 | 9.f. Improved Uninterruptible Power Supplies | SAMA would provide increased reliability of power supplies supporting front-line equipment, thus reducing core damage and release frequencies. |
| 121 | 9.g. AC Bus Cross-Ties | SAMA would provide increased reliability of AC power system to reduce core damage and release frequencies. |
| 122 | 9.h. Gas Turbine | SAMA would improve onsite AC power reliability by providing a redundant and diverse emergency power system. |
| 123 | 9.i. Dedicated RHR (bunkered) Power Supply | SAMA would provide RHR with more reliable AC power. |
| 124 | 10.a. Dedicated DC Power Supply | This SAMA addresses the use of a diverse DC power system such as an additional battery or fuel cell for the purpose of providing motive power to certain components (e.g., RCIC). |
| 125 | 10.b. Additional Batteries/Divisions | This SAMA addresses the use of a diverse DC power system such as an additional battery or fuel cell for the purpose of providing motive power to certain components (e.g., RCIC). |
| 126 | 10.c. Fuel Cells | SAMA would extend DC power availability in an SBO. |
| 127 | 10.d. DC Cross-ties | This SAMA would improve DC power reliability. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 128 | 10.e. Extended Station Blackout Provisions | SAMA would provide reduction in SBO sequence frequencies. |
| 129 | Add an automatic bus transfer feature to allow the automatic transfer of the 120V vital AC bus from the on-line unit to the standby unit | Plants are typically sensitive to the loss of one or more 120V vital AC buses. Manual transfers to alternate power supplies could be enhanced to transfer automatically. |
| | **Improvements in Identifying and Mitigating Containment Bypass** | |
| 130 | Install a redundant spray system to depressurize the primary system during a steam generator tube rupture (SGTR). | SAMA would enhance depressurization during a SGTR. |
| 131 | Improve SGTR coping abilities. | SAMA would improve instrumentation to detect SGTR, or additional system to scrub fission product releases. |
| 132 | Add other SGTR coping abilities. | SAMA would decrease the consequences of an SGTR. |
| 133 | Increase secondary side pressure capacity such that an SGTR would not cause the relief valves to lift. | SAMA would eliminate direct release pathway for SGTR sequences. |
| 134 | Replace steam generators (SG) with a new design. | SAMA would lower the frequency of an SGTR. |
| 135 | Revise EOPs to direct that a faulted SG be isolated. | SAMA would reduce the consequences of an SGTR. |
| 136 | Direct SG flooding after a SGTR, prior to core damage. | SAMA would provide for improved scrubbing of SGTR releases. |
| 137 | Implement a maintenance practice that inspects 100% of the tubes in a SG. | SAMA would reduce the potential for an SGTR. |
| 138 | Locate residual heat removal (RHR) inside of containment. | SAMA would prevent intersystem LOCA (ISLOCA) out the RHR pathway. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 139 | Install additional instrumentation for ISLOCAs. | SAMA would decrease ISLOCA frequency by installing pressure of leak monitoring instruments in between the first two pressure isolation valves on low-pressure inject lines, RHR suction lines, and HPSI lines. |
| 140 | Increase frequency for valve leak testing. | SAMA could reduce ISLOCA frequency. |
| 141 | Improve operator training on ISLOCA coping. | SAMA would decrease ISLOCA effects. |
| 142 | Install relief valves in the CC System. | SAMA would relieve pressure buildup from an RCP thermal barrier tube rupture, preventing an ISLOCA. |
| 143 | Provide leak testing of valves in ISLOCA paths. | SAMA would help reduce ISLOCA frequency. At Kewaunee Nuclear Power Plant, four MOVs isolating RHR from the RCS were not leak tested. |
| 144 | Revise EOPs to improve ISLOCA identification. | SAMA would ensure LOCA outside containment could be identified as such. Salem Nuclear Power Plant had a scenario where an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment. |
| 145 | Ensure all ISLOCA releases are scrubbed. | SAMA would scrub all ISLOCA releases. One example is to plug drains in the break area so that the break point would be covered with water. |
| 146 | Add redundant and diverse limit switches to each containment isolation valve. | SAMA could reduce the frequency of containment isolation failure and ISLOCAs through enhanced isolation valve position indication. |
| 147 | Early detection and mitigation of ISLOCA | SAMA would limit the effects of ISLOCA accidents by early detection and isolation |
| 148 | 8.e. Improved MSIV Design | This SAMA would improve isolation reliability and reduce spurious actuations that could be initiating events. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 149 | Proceduralize use of pressurizer vent valves during steam generator tube rupture (SGTR) sequences | Some plants may have procedures to direct the use of pressurizer sprays to reduce RCS pressure after an SGTR. Use of the vent valves would provide a back-up method. |
| 150 | Implement a maintenance practice that inspects 100% of the tubes in an SG | This SAMA would reduce the potential for a tube rupture. |
| 151 | Locate RHR inside of containment | This SAMA would prevent ISLOCA out the RHR pathway. |
| 152 | Install self-actuating containment isolation valves | For plants that do not have this, it would reduce the frequency of isolation failure. |
| | **Improvements in Reducing Internal Flooding Frequency** | |
| 153 | Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment. | SAMA would prevent flood propagation, for a plant where internal flooding from turbine building to safeguards areas is a concern. |
| 154 | Improve inspection of rubber expansion joints on main condenser. | SAMA would reduce the frequency of internal flooding, for a plant where internal flooding due to a failure of circulating water system expansion joints is a concern. |
| 155 | Implement internal flood prevention and mitigation enhancements. | This SAMA would reduce the consequences of internal flooding. |
| 156 | Implement internal flooding improvements such as those implemented at Fort Calhoun. | This SAMA would reduce flooding risk by preventing or mitigating rupture in the RCP seal cooler of the component cooling system and ISLOCA in a shutdown cooling line, an auxiliary feedwater (AFW) flood involving the need to remove a watertight door. |
| 157 | Shield electrical equipment from potential water spray | SAMA would decrease risk associated with seismically induced internal flooding |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 158 | 13.c. Reduction in Reactor Building Flooding (BWR only) | This SAMA reduces the Reactor Building Flood Scenarios contribution to core damage and release. |
| | **Improvements Related to Feedwater/Feed and Bleed Reliability/Availability** | |
| 159 | Install a digital feedwater upgrade. | This SAMA would reduce the chance of a loss of main feedwater following a plant trip. |
| 160 | Perform surveillances on manual valves used for backup AFW pump suction. | This SAMA would improve success probability for providing alternative water supply to the AFW pumps. |
| 161 | Install manual isolation valves around AFW turbine-driven steam admission valves. | This SAMA would reduce the dual turbine-driven AFW pump maintenance unavailability. |
| 162 | Install accumulators for turbine-driven AFW pump flow control valves (CVs). | This SAMA would provide control air accumulators for the turbine-driven AFW flow CVs, the motor-driven AFW pressure CVs and SG power-operated relief valves (PORVs). This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOOP. |
| 163 | Install separate accumulators for the AFW cross-connect and block valves | This SAMA would enhance the operator's ability to operate the AFW cross-connect and block valves following loss of air support. |
| 164 | Install a new condensate storage tank (CST) | Either replace the existing tank with a larger one, or install a back-up tank. |
| 165 | Provide cooling of the steam-driven AFW pump in an SBO event | This SAMA would improve success probability in an SBO by: (1) using the FP system to cool the pump, or (2) making the pump self cooled. |
| 166 | Proceduralize local manual operation of AFW when control power is lost. | This SAMA would lengthen AFW availability in an SBO. Also provides a success path should AFW control power be lost in non-SBO sequences. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 167 | Provide portable generators to be hooked into the turbine driven AFW, after battery depletion. | This SAMA would extend AFW availability in an SBO (assuming the turbine driven AFW requires DC power) |
| 168 | Add a motor train of AFW to the Steam trains | For PWRs that do not have any motor trains of AFW, this would increase reliability in non-SBO sequences. |
| 169 | Create ability for emergency connections of existing or alternate water sources to feedwater/condensate | This SAMA would be a back-up water supply for the feedwater/condensate systems. |
| 170 | Use FP system as a back-up for SG inventory | This SAMA would create a back-up to main and AFW for SG water supply. |
| 171 | Procure a portable diesel pump for isolation condenser make-up (BWR only) | This SAMA would provide a back-up to the city water supply and diesel FP system pump for isolation condenser make-up. |
| 172 | Install an independent diesel generator for the CST make-up pumps | This SAMA would allow continued inventory make-up to the CST during an SBO. |
| 173 | Change failure position of condenser make-up valve | This SAMA would allow greater inventory for the AFW pumps by preventing CST flow diversion to the condenser if the condenser make-up valve fails open on loss of air or power. |
| 174 | Create passive secondary side coolers. | This SAMA would reduce CDF from the loss of Feedwater by providing a passive heat removal loop with a condenser and heat sink. |
| 175 | Replace current PORVs with larger ones such that only one is required for successful feed and bleed. | This SAMA would reduce the dependencies required for successful feed and bleed. |
| 176 | Install motor-driven feedwater pump. | SAMA would increase the availability of injection subsequent to MSIV closure. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 177 | Use Main FW pumps for a Loss of Heat Sink Event | This SAMA involves a procedural change that would allow for a faster response to loss of the secondary heat sink. Use of only the feedwater booster pumps for injection to the SGs requires depressurization to about 350 psig; before the time this pressure is reached, conditions would be met for initiating feed and bleed. Using the available turbine driven feedwater pumps to inject water into the SGs at a high pressure rather than using the feedwater booster alone allows injection without the time consuming depressurization. |
| | **Improvements in Core Cooling Systems** | |
| 178 | Provide the capability for diesel driven, low pressure vessel make-up | This SAMA would provide an extra water source in sequences in which the reactor is depressurized and all other injection is unavailable (e.g., FP system) |
| 179 | Provide an additional HPSI pump with an independent diesel | This SAMA would reduce the frequency of core melt from small LOCA and SBO sequences |
| 180 | Install an independent AC HPSI system | This SAMA would allow make-up and feed and bleed capabilities during an SBO. |
| 181 | Create the ability to manually align ECCS recirculation | This SAMA would provide a back-up should automatic or remote operation fail. |
| 182 | Implement an RWT make-up procedure | This SAMA would decrease CDF from ISLOCA scenarios, some smaller break LOCA scenarios, and SGTR. |
| 183 | Stop low pressure safety injection pumps earlier in medium or large LOCAs. | This SAMA would provide more time to perform recirculation swap over. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 184 | Emphasize timely swap over in operator training. | This SAMA would reduce human error probability of recirculation failure. |
| 185 | Upgrade Chemical and Volume Control System to mitigate small LOCAs. | For a plant like the AP600 where the Chemical and Volume Control System cannot mitigate a Small LOCA, an upgrade would decrease the Small LOCA CDF contribution. |
| 186 | Install an active HPSI system. | For a plant like the AP600 where an active HPSI system does not exist, this SAMA would add redundancy in HPSI. |
| 187 | Change "in-containment" RWT suction from 4 check valves to 2 check and 2 air operated valves. | This SAMA would remove common mode failure of all four injection paths. |
| 188 | Replace 2 of the 4 safety injection (SI) pumps with diesel-powered pumps. | This SAMA would reduce the SI system common cause failure probability. This SAMA was intended for the System 80+, which has four trains of SI. |
| 189 | Align low pressure core injection or core spray to the CST on loss of suppression pool cooling (BWR only). | This SAMA would help to ensure low pressure ECCS can be maintained in loss of suppression pool cooling scenarios. |
| 190 | Raise high pressure core injection/reactor core isolation cooling backpressure trip setpoints (BWR only) | This SAMA would ensure high pressure core injection/reactor core isolation cooling availability when high suppression pool temperatures exist. |
| 191 | Improve the reliability of the automatic depressurization system (BWR only). | This SAMA would reduce the frequency of high pressure core damage sequences. |
| 192 | Disallow automatic vessel depressurization in non-ATWS scenarios | This SAMA would improve operator control of the plant. |
| 193 | Create automatic swap over to recirculation on RWT depletion | This SAMA would reduce the human error contribution from recirculation failure. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 194 | Proceduralize intermittent operation of HPCI (BWR only). | SAMA would allow for extended duration of HPCI availability. |
| 195 | Increase available net positive suction head (NPSH) for injection pumps. | SAMA increases the probability that these pumps will be available to inject coolant into the vessel by increasing the available NPSH for the injection pumps. |
| 196 | Modify Reactor Water Cleanup (RWCU) for use as a decay heat removal system and proceduralize use (BWR only). | SAMA would provide an additional source of decay heat removal. |
| 197 | CRD Injection (BWR only) | SAMA would supply an additional method of level restoration by using a non-safety system. |
| 198 | Condensate Pumps for Injection (BWR only) | SAMA to provide an additional option for coolant injection when other systems are unavailable or inadequate |
| 199 | Align EDG to CRD for Injection (BWR only) | SAMA to provide power to an additional injection source during loss of power events |
| 200 | Re-open MSIVs (BWR only) | SAMA to regain the main condenser as a heat sink by re-opening the MSIVs. |
| 201 | Bypass RCIC Turbine Exhaust Pressure Trip (BWR only) | SAMA would allow RCIC to operate longer. |
| 202 | 2.a. Passive High Pressure System | SAMA will improve prevention of core melt sequences by providing additional high pressure capability to remove decay heat through an isolation condenser type system |
| 203 | 2.c. Suppression Pool Jockey Pump (BWR only) | SAMA will improve prevention of core melt sequences by providing a small makeup pump to provide low pressure decay heat removal from the RPV using the suppression pool as a source of water. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 204 | 2.d. Improved High Pressure Systems | SAMA will improve prevention of core melt sequences by improving reliability of high pressure capability to remove decay heat. |
| 205 | 2.e. Additional Active High Pressure System | SAMA will improve reliability of high pressure decay heat removal by adding an additional system. |
| 206 | 2.f. Improved Low Pressure System (Firepump) | SAMA would provide FP system pump(s) for use in low pressure scenarios. |
| 207 | 4.b. Clean Up Water Decay Heat Removal (BWR only) | This SAMA provides a means for Alternate Decay Heat Removal. |
| 208 | 4.c. High Flow Suppression Pool Cooling (BWR only) | SAMA would improve suppression pool cooling. |
| 209 | 8.c. Diverse Injection System | SAMA will improve prevention of core melt sequences by providing additional injection capabilities. |
| 210 | Alternate Charging Pump Cooling | This SAMA will improve the high pressure core flooding capabilities by providing the SI pumps with alternate gear and oil cooling sources. Given a total loss of Chilled Water, abnormal operating procedures would direct alignment of preferred Demineralized Water or the Fire System to the Chilled Water System to provide cooling to the SI pumps' gear and oil box (and the other normal loads). |
| | **Instrument Air/Gas Improvements** | |
| 211 | Modify EOPs for ability to align diesel power to more air compressors. | For plants that do not have diesel power to all normal and back-up air compressors, this change would increase the reliability of IA after a LOOP. |
| 212 | Replace old air compressors with more reliable ones | This SAMA would improve reliability and increase availability of the IA compressors. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 213 | Install nitrogen bottles as a back-up gas supply for safety relief valves (BWR only). | This SAMA would extend operation of safety relief valves during an SBO and loss of air events (BWRs). |
| 214 | Allow cross connection of uninterruptible compressed air supply to opposite unit. | SAMA would increase the ability to vent containment using the hardened vent. |
| | **ATWS Mitigation** | |
| 215 | Install MG set trip breakers in control room (BWR only) | This SAMA would provide trip breakers for the MG sets in the control room. In some plants, MG set breaker trip requires action to be taken outside of the control room. Adding control capability to the control room would reduce the trip failure probability in sequences where immediate action is required (e.g., ATWS). |
| 216 | Add capability to remove power from the bus powering the control rods | This SAMA would decrease the time to insert the control rods if the reactor trip breakers fail (during a loss of FW ATWS which has a rapid pressure excursion) |
| 217 | Create cross-connect ability for standby liquid control trains (BWR only) | This SAMA would improve reliability for boron injection during an ATWS event. |
| 218 | Create an alternate boron injection capability (back-up to standby liquid control) (BWR only) | This SAMA would improve reliability for boron injection during an ATWS event. |
| 219 | Remove or allow override of low pressure core injection during an ATWS (BWR only) | On failure on high pressure core injection and condensate, some plants direct reactor depressurization followed by 5 minutes of low pressure core injection. This SAMA would allow control of low pressure core injection immediately. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 220 | Install a system of relief valves that prevents any equipment damage from a pressure spike during an ATWS | This SAMA would improve equipment availability after an ATWS. |
| 221 | Create a boron injection system to back up the mechanical control rods. | This SAMA would provide a redundant means to shut down the reactor. |
| 222 | Provide an additional instrument system for ATWS mitigation (e.g., ATWS mitigation scram actuation circuitry). | This SAMA would improve instrument and control redundancy and reduce the ATWS frequency. |
| 223 | Increase the safety relief valve (SRV) reseat reliability (BWR only). | SAMA addresses the risk associated with dilution of boron caused by the failure of the SRVs to reseat after standby liquid control (SBLC) injection. |
| 224 | Use control rod drive for alternate boron injection (BWR only). | SAMA provides an additional system to address ATWS with SBLC failure or unavailability. |
| 225 | Bypass MSIV isolation in Turbine Trip ATWS scenarios (BWR only) | SAMA will afford operators more time to perform actions. The discharge of a substantial fraction of steam to the main condenser (i.e., as opposed to into the primary containment) affords the operator more time to perform actions (e.g., SBLC injection, lower water level, depressurize RPV) than if the main condenser was unavailable, resulting in lower human error probabilities |
| 226 | Enhance operator actions during ATWS | SAMA will reduce human error probabilities during ATWS |
| 227 | Guard against SBLC dilution (BWR only) | SAMA to control vessel injection to prevent boron loss or dilution following SBLC injection. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 228 | 11.a. ATWS Sized Vent | This SAMA would be providing the ability to remove reactor heat from ATWS events. |
| 229 | 11.b. Improved ATWS Capability | This SAMA includes items which reduce the contribution of ATWS to core damage and release frequencies. |
| | **Other Improvements** | |
| 230 | Provide capability for remote operation of secondary side relief valves in an SBO | Manual operation of these valves is required in an SBO scenario. High area temperatures may be encountered in this case (no ventilation to main steam areas), and remote operation could improve success probability. |
| 231 | Create/enhance RCS depressurization ability | With either a new depressurization system, or with existing PORVs, head vents, and secondary side valve, RCS depressurization would allow earlier low pressure ECCS injection. Even if core damage occurs, low RCS pressure would alleviate some concerns about high pressure melt ejection. |
| 232 | Make procedural changes only for the RCS depressurization option | This SAMA would reduce RCS pressure without the cost of a new system |
| 233 | Defeat 100% load rejection capability. | This SAMA would eliminate the possibility of a stuck open PORV after a LOOP, since PORV opening would not be needed. |
| 234 | Change control rod drive flow control valve failure position (BWR only) | Change failure position to the "fail-safest" position. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 235 | Install secondary side guard pipes up to the MSIVs | This SAMA would prevent secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. This SAMA would also guard against or prevent consequential multiple SGTR following a Main Steam Line Break event. |
| 236 | Install digital large break LOCA protection | Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (leak before break). |
| 237 | Increase seismic capacity of the plant to a high confidence, low pressure failure of twice the Safe Shutdown Earthquake. | This SAMA would reduce seismically -induced CDF. |
| 238 | Enhance the reliability of the demineralized water (DW) make-up system through the addition of diesel-backed power to one or both of the DW make-up pumps. | Inventory loss due to normal leakage can result in the failure of the CC and the SRW systems. Loss of CC could challenge the RCP seals. Loss of SRW results in the loss of three EDGs and the containment air coolers (CACs). |
| 239 | Increase the reliability of safety relief valves by adding signals to open them automatically (BWR only). | SAMA reduces the probability of a certain type of medium break LOCA. Hatch evaluated medium LOCA initiated by an MSIV closure transient with a failure of SRVs to open. Reducing the likelihood of the failure for SRVs to open, subsequently reduces the occurrence of this medium LOCA. |
| 240 | Reduce DC dependency between high pressure injection system and ADS (BWR only). | SAMA would ensure containment depressurization and high pressure injection upon a DC failure. |
| 241 | Increase seismic ruggedness of plant components. | SAMA would increase the availability of necessary plant equipment during and after seismic events. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 242 | Enhance RPV depressurization capability (BWR only) | SAMA would decrease the likelihood of core damage in loss of high pressure coolant injection scenarios |
| 243 | Enhance RPV depressurization procedures (BWR only) | SAMA would decrease the likelihood of core damage in loss of high pressure coolant injection scenarios |
| 244 | Replace mercury switches on FP systems | SAMA would decrease probability of spurious fire suppression system actuation given a seismic event+D114 |
| 245 | Provide additional restraints for $CO_2$ tanks | SAMA would increase availability of FP given a seismic event. |
| 246 | Enhance control of transient combustibles | SAMA would minimize risk associated with important fire areas. |
| 247 | Enhance fire brigade awareness | SAMA would minimize risk associated with important fire areas. |
| 248 | Upgrade fire compartment barriers | SAMA would minimize risk associated with important fire areas. |
| 249 | Enhance procedures to allow specific operator actions | SAMA would minimize risk associated with important fire areas. |
| 250 | Develop procedures for transportation and nearby facility accidents | SAMA would minimize risk associated with transportation and nearby facility accidents. |
| 251 | Enhance procedures to mitigate Large LOCA | SAMA would minimize risk associated with Large LOCA |
| 252 | 1.b. Computer Aided Instrumentation | SAMA will improve prevention of core melt sequences by making operator actions more reliable. |
| 253 | 1.c/d. Improved Maintenance Procedures/Manuals | SAMA will improve prevention of core melt sequences by increasing reliability of important equipment |
| 254 | 1.e. Improved Accident Management Instrumentation | SAMA will improve prevention of core melt sequences by making operator actions more reliable. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 255 | 1.f. Remote Shutdown Station | This SAMA would provide the capability to control the reactor in the event that evacuation of the main control room is required. |
| 256 | 1.g. Security System | Improvements in the site's security system would decrease the potential for successful sabotage. |
| 257 | 2.b. Improved Depressurization | SAMA will improve depressurization system to allow more reliable access to low pressure systems. |
| 258 | 2.h. Safety Related Condensate Storage Tank | SAMA will improve availability of CST following a Seismic event |
| 259 | 4.d. Passive Overpressure Relief | This SAMA would prevent vessel overpressurization. |
| 260 | 8.b. Improved Operating Response | Improved operator reliability would improve accident mitigation and prevention. |
| 261 | 8.d. Operation Experience Feedback | This SAMA would identify areas requiring increased attention in plant operation through review of equipment performance. |
| 262 | 8.e. Improved SRV Design | This SAMA would improve SRV reliability, thus increasing the likelihood that sequences could be mitigated using low pressure heat removal. |
| 263 | 12.a. Increased Seismic Margins | This SAMA would reduce the risk of core damage and release during seismic events. |
| 264 | 13.b. System Simplification | This SAMA is intended to address system simplification by the elimination of unnecessary interlocks, automatic initiation of manual actions or redundancy as a means to reduce overall plant risk. |

## Addendum 1 Selected Previous Industry SAMAs (Continued)

| SAMA ID Number | SAMA Title | Result of Potential Enhancement |
|---|---|---|
| 265 | Train operations crew for response to inadvertent actuation signals | This SAMA would improve chances of a successful response to the loss of two 120V AC buses, which may cause inadvertent signal generation. |
| 266 | Install tornado protection on gas turbine generators | This SAMA would improve onsite AC power reliability. |