PrairieIslandNPEm Resource

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Here's the second part

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Enclosure 1
Responses to NRC Requests for Additional Information Dated October 23, 2008

RAI SAMA 3.a

Provide the following information regarding the treatment of external events in the SAMA analysis:

a. Provide a summary of the dominant fire scenarios for the individual plant examination of external events (IPEEE) fire model in terms of overall fire frequency, plant initiator, and structures, systems, and components (SSCs) impacted. Demonstrate for each fire scenario that no viable SAMA candidates exist to reduce fire risk.

NSPM Response to RAI SAMA 3.a

A complete discussion of dominant fire scenarios for the IPEEE Fire risk analysis, including the requested information on frequency, initiator and SSCs impacted, is provided in the IPEEE Rev. 1, Section B.1.4, and supporting table B.2.11.1.

For the ER SAMA analysis, fire area-specific SAMA candidates were not developed. The Fire IPEEE was performed using a Fire PRA built on the Unit 1 Level 1 Revision 1 (1L1R1) PRA model. As described in Section F.2.1.2.1, the 1L1R1 model was completed in 1996 and was the first major revision of the PRA model since the IPE. This was a Unit 1-only, Level 1-only model, and did not include an estimate of the LERF metric for Unit 1. In the twelve years since the 1L1R1 model was implemented, numerous plant modifications, procedure changes and risk analysis methodology changes have been incorporated, and model enhancements have been made in response to industry peer certification comments. As a result, significant changes to the calculated CDF and distribution of dominant accident sequences and contributors are evident when comparing the results of the 1L1R1 and Unit 1 Rev. 2.2 SAMA models. Section F.2 of the ER shows the changes that have been reflected in the Level 1 and Level 2 PRA models since the 1L1R1 model was implemented. Also, methodologies associated with Fire PRA have been improved over the ten years since the Fire IPEEE was developed. The Fire PRA methodologies used in the Fire IPEEE analysis differ from current industry methodology (NUREG/CR-6850, etc.). Also, as discussed in the response to RAI SAMA 3.b, the Fire IPEEE results include significant conservative assumptions, even in the sequences that were found to dominate the risk profile. The fire CDF of 4.9E-5/yr reported in the Fire IPEEE is considered to be a conservative upper bound for that (1998-vintage) risk model. Due to these considerations, it was concluded that an evaluation of fire area-specific SAMA candidates using the IPEEE would not provide valid results.

From the Fire IPEEE, Section B.1.4, the CDF from internal fires is spread across five accident classes:

1. [66%] Accident class TEH is comprised of transient (i.e., fire) initiated events with loss of secondary heat removal (loss of MFW and AFW) and failure of bleed and feed. Reactor pressure is high at the time of core damage. Core damage occurs within approximately 2 hours of the loss of heat removal.
2. [19%]The SEH accident class for the IPEEE consists of RCP seal LOCA initiated events, or events that progress similar to small LOCAs due to fire-induced spurious equipment actuation, in which high head safety injection is not capable of preventing core damage. Reactor pressure is high at the time of core damage, which occurs relatively early (see TEH).

3. [11%]The BEH accident class involves fires that cause the loss of offsite power, and onsite power is not successfully restored prior to core damage. Only one initiating fire was determined to lead to loss of offsite power, a large fire in the control room "G" control panel. A fire large enough in this panel could affect both trains of offsite power, and the recovery of both offsite and onsite power from the control room. In this event, credit is given for operator response to locally restore onsite AC power from the emergency diesel generators according to established plant procedures.
4. [2%]Accident class SLH is similar to the SEH class, except that high head safety injection is successful. Long term recirculation cooling of the RCS then fails, leading to late core damage at high pressure.
5. [2%]Accident class TLH is characterized by transient initiated events with loss of secondary heat removal, successful bleed and feed but failure of recirculation. Reactor pressure is high at the time of core damage, which occurs on the order of 10 hours after the loss of secondary cooling.

Each of these accident classes correspond to accident classes used in the internal events PRA models. Except for the fire suppression response, most of the equipment and operator actions necessary to mitigate most fire-induced transients and LOCAs are the same as those that are necessary to mitigate transients and LOCAs caused or induced by internal initiating events. Therefore, all SAMAs identified in the ER with risk benefits that are not limited only to containment bypass events, LOCA events larger than a small LOCA, and reduction of the frequency of internal initiating events, will also act to reduce the core damage risk associated with internal fires (to various degrees, depending on the SAMA). Of the SAMAs described in the ER, the only SAMAs that do not also act to reduce internal fires risk are:

- The SAMAs that only limit the impact of internal flooding events (SAMAs 6, 6a and 13); and
- The SAMAs that only improve the risk associated with ISLOCA events (SAMAs 19 and 20).

All of the other SAMAs identified in the ER would also function to reduce the risk of events initiated by internal fires.

The above considerations notwithstanding, a number of additional SAMAs that attempt to specifically address the risk from internal fires were developed in response to this RAI question. Many of these SAMAs are general in nature, as a focus on individual fires or fire areas may not be appropriate given the number of changes to the plant, procedures and risk analysis models that have occurred since the IPEEE was issued. The following table describes these alternatives and their disposition for PINGP:

Phase 1 SAMA ID#	SAMA Title	Result of Potential Enhancement	Screening Basis	Disposition
1	Enhance control of transient combustibles and ignition sources	SAMA would minimize risk associated with important fire areas by decreasing the	Already implemented	Procedures to control the use, location and amount of combustible material and ignition sources are in place at PINGP. Deficiencies are captured in the Corrective Action Program.

Phase 1 SAMA ID#	SAMA Title	Result of Potential Enhancement	Screening Basis	Disposition
		frequency of fires and their consequences.		
2	Enhance fire brigade awareness	SAMA would minimize risk associated with important fire areas by decreasing the duration and consequences of fires.	Already implemented	Credit for manual fire suppression was given only for fires in the Control Room and Relay Room in the Fire IPEEE. A procedure provides specific instructions on the organization of fire brigades, training and qualification of individual fire brigade members, individual responsibilities in regard to fires, and procedures for extinguishing fires. Operations emergency responses for fires located in specific locations is covered in subsections of this procedure and in the site Emergency Plan Individual Fire Brigade members are required to actively participate in at least two (2) drills per year. PRA insights, including dominant fire sequences from the Fire IPEEE analysis, are included in the operations initial and requalification training programs
3	Upgrade fire compartment barriers	SAMA would minimize risk associated with important fire areas.	Already implemented	PINGP fire compartment barriers are monitored and maintained operable to reduce fire propagation. Operability requirements and surveillance frequencies are identified in plant procedures. Barriers found to be inoperable are required to have a fire watch or patrol established (assuming operable fire detectors) on one side of the affected barrier within 1 hour. Other compensatory measures may be established in lieu of these requirements if they are determined to be more effective (the use of such measures is controlled according to procedure and requires an evaluation that includes risk insights).
4	Enhance procedures to allow specific operator actions	SAMA would reduce the risk associated with important fire areas by reducing the consequences of fires.	Already implemented	PINGP safe shutdown procedures are available for use to accomplish safe shutdown in response to fires. The purpose of these procedures is to outline those actions necessary to safely shut down the plant in the event that the Control Room must be evacuated, or there is a fire in the Relay Room or other plant area affecting the operation of equipment needed for safe shutdown. Operations emergency response for fires located in specific locations is covered in subsections of these procedures and in the site Emergency Plan.
5	Enhance procedures associated with plant shutdown from	This SAMA would allow alternate system control in the event that the Control Room	Already implemented	PINGP procedures outline those actions necessary to safely shut down the plant in the event that the Control Room becomes uninhabitable due to a fire.

Phase 1 SAMA ID#	SAMA Title	Result of Potential Enhancement	Screening Basis	Disposition
	the Hot Shutdown Panel	becomes uninhabitable.		
6	Isolate combustible sources for seismic or other events	This SAMA would reduce risk by limiting the volume of flammable or combustible materials that may emanate from piping systems damaged during seismic events.	Already implemented	See discussion of item #1 above. In addition, the IPEEE analysis included a review of seismic/fire interactions. As part of the seismic assessment walkdown, it was verified that hydrogen or other flammable gas or liquid storage vessels in areas with safety related equipment are not subject to leakage under seismic conditions. The potential failure of vessels containing flammable or combustible liquids or gases could cause a fire hazard in the plant following an earthquake. As a part of the seismic walkdowns, a survey of tanks and vessels that may contain flammable fluids was performed. The IPEEE review concluded that these issues are not significant contributors to fire-induced core damage at Prairie Island.
7	Restrain or locate cabinets containing flammable materials to reduce the likelihood of overturning caused by seismic or other events	This SAMA would reduce risk by reducing the potential for cabinets overturning and spilling flammable liquid contents.	Already implemented	See discussion of Item #6 above.
8	Ensure that the quantity of combustible materials in critical process areas is monitored	This SAMA would reduce risk by reducing the potential for a prolonged fire to develop in safety-related areas.	Already implemented	PINGP has controls governing the fire-safe use and storage of combustible materials within the process buildings. The Fire Hazard Analysis documents the analyzed combustible loading in each fire area. Plant procedures require a Combustible Control Permit (CCP) for any work involving a fire hazard, and prior to temporary or permanent storage of combustible material the additional combustible loading must be analyzed through the CCP process.
9	Limit switches and torque switches would not be bypassed during a fire induced hot short for Control Room and Relay	This SAMA would address the reconfiguration of the MOVs control circuits and protect the motor operator via the limit and torque switches due to the fire induced	Already implemented	PINGP has reconfigured the control circuits of a number of Appendix R motor-operated valves to address hot short concerns of NRC Information Notice IN 92-18.

Phase 1 SAMA ID#	SAMA Title	Result of Potential Enhancement	Screening Basis	Disposition
	Room fire events	hot short.		
11	Relocate instrument air compressors out of the AFW pump rooms	This SAMA would reduce risk by reducing the potential for fire ignition and development of large fires in AFW pump rooms. Potential risk benefits to both units.	High implementation cost	This modification with potential as a fire-related risk mitigation measure is currently in progress. This is a very complex and expensive plant modification that may not be cost-justifiable based on risk-reduction alone. The site MMACR from ER Section F.4.6 was just over \$4 million; the current cost estimate for this modification is >\$4 million. Instrument Air is not lost in most of the top internal events CDF and LERF sequence cutsets. Fire IPEEE showed fires in AFW/IA compressor room to contribute only 16.7% of fire CDF.
12	Re-route cables that currently exist in risk-significant fire areas	This SAMA would reduce risk by reducing the consequences of a fire in risk-significant fire areas.	High implementation cost	Re-route of individual cables can provide highly targeted risk reduction for certain fire scenarios. However, the risk reduction is unlikely to offset the high cost of these modifications.

Refer to Section F.5.1.6 of the ER for a discussion of how the recommendations developed from the IPEEE insights were dispositioned.

RAI SAMA 3.b

b. ER Section F.5.1.8 indicates that the maximum averted cost-risk (MACR) for internal events was doubled to account for external events contributions. However, ER Section F.5.1.7.2 indicates that the IPEEE fire CDF is about 5E-5 per year, which is approximately five times the internal event CDF. (This value is stated as being conservative in part due to not crediting automatic and manual fire suppression.)

   Furthermore, in a July 21, 2006, request for additional information (RAI) response related to an extension of the containment integrated leakage rate test (ML062060033), Nuclear Management Company, LLC estimated the seismic CDF for Prairie Island Nuclear Generating Plant (PINGP) to be 7.82E-6 per year. Provide additional justification for use of a multiplier of 2 given that the fire CDF is approximately five times the current internal events CDF, that credit for automatic and manual fire suppression has been included for many of the dominant fire sequences, and that seismic and other external events also contribute to the total CDF.

NSPM Response to RAI SAMA 3.b

Internal Fires

From the results of the PINGP IPEEE, it can be reasonably concluded that the majority of the external events risk at PINGP is due to internal fires. Both the IPE CDF (5.0E-5/rx-yr) and the fire CDF from the IPEEE (4.9E-5/rx-yr) are comparable and of the same magnitude. These two analyses were performed within four years of each other in the mid-1990s, and were based on conservative modeling methodologies consistent with state-of-the-knowledge at the time. In addition, the purpose of the Fire IPEEE analysis was to meet Generic Letter 88-20 requirements (identify vulnerabilities to severe accidents initiated by internal fires), and was not to determine the internal fires CDF to a high degree of accuracy. The analysis contained numerous conservative assumptions for which (in alignment with the original purpose of the analysis and available analysis resources) further refinement was unnecessary. The fire IPEEE CDF can be considered to be an estimate of the upper bound risk of internal fires that existed at that time, based on then-available methodologies.

Therefore, it is not appropriate to compare a conservative CDF estimate for fire hazards based on the IPEEE to the present-day internal events CDF, which is based on more refined modeling techniques and analyses. In fact, the IPEEE CDF due to fires would be expected to decline along with the CDF due to internal events, since the plant response to fire damage is not unlike the plant response to plant transients due to equipment failures and other internal events. Since the Fire IPEEE analysis was completed, the conditional core damage probability (CCDP) associated with normal (or general) plant transient-initiated events on Unit 1 (as calculated for the updated internal events PRA model) has fallen by 46%. This fact, independent of fire PRA methodology improvements now available, supports NSPM's belief that the current, actual Fire CDF is significantly lower than the value calculated for the IPEEE.

As stated above, there were a number of significant, conservative assumptions included in the Fire IPEEE that could be refined using currently available methodologies to determine a more realistic estimate of the current fire CDF.

- All fires (any size) were conservatively assumed to result in shutdown of both units. One impact of this conservatism relates to the ability to credit cross-tie of the motor-driven AFW pump (MDAFWP) from the opposite unit to the steam generators (SGs) of the unit experiencing the fire. A limitation on this crosstie was included in the fault tree for AFW such that if a dual unit initiating event occurred and the opposite unit turbine-driven AFW pump (TDAFWP) failed, the opposite unit MDAFWP could not be cross-tied to the fire-affected unit as it would be required to support the SGs on its own unit. As all fires were conservatively assumed to result in shutdown of both units, credit for this crosstie is limited if random or fire-associated failures impacting the opposite unit TDAFWP were assumed to occur.

- Credit given in IPEEE for automatic and manual suppression was limited. A large portion of IPEEE fire CDF could be significantly reduced through additional application of credit for automatic or manual suppression. In the IPEEE, credit was only applied to cutsets representing <13% of the internal fires CDF.

- No credit was given for the ability of fire brigade to extinguish local fires before shutdown of the plant would be required.
- Credit only applied to Control Room, Relay Room, and certain AFW pump room fires. Only automatic fire suppression was credited in the AFW pump rooms.
- No detailed analysis of Human Error Probabilities (HEPs) for failure of manual fire suppression was performed for fires in any fire area.

- No credit was given to the availability of the RCS PORV passive air accumulators located inside containment to provide support for bleed and feed (B&F) cooling of the RCS. For any fire that is assumed to impact the instrument air (IA) system, B&F is assumed to fail. This is an important consideration in a number of dominant IPEEE fire areas (FA) in which main feedwater or AFW is also impacted. For example, the response to the fires occurring in FA 13 (Control Room panel zones 5 & 6) and FA 32 (AFW pump room) described below are significantly impacted by this conservative treatment. Credit is now given in the internal events PRA analysis for the availability of this equipment (see response to RAI question 6.d).

- Detailed fire modeling was not performed in a number of fire areas that did not screen out of the analysis, including the Bus 16 and Bus 111 switchgear rooms and three large fire areas covering the entire floor elevation for a given unit in the Auxiliary and Turbine buildings.

The Fire IPEEE results showed that fires originating in two Unit 1 plant fire areas contributed approximately 82% of the total internal fires CDF. No other individual fire areas contributed more than 4.5% of the CDF. Conservative assumptions in the IPEEE analysis specific to these areas include:

- <u>Control Room (CRM) – FA 13 (65.3%, 3.22E-5/yr):</u>
  - Except for fires in the G-panel, small control room panel fires (those that are not large enough to propagate outside the control board zone in which they initiate) are assumed to cause the loss of all equipment within that panel zone. No credit for cable separation to allow partitioning of these cabinet fires further was given.
  - CRM Panel Zones 5, 6 fires (LOFW/AFW) (~40% of total fire IPEEE CDF, almost 2E-5/yr)
    - Almost all sequences include failure of B&F or recirculation
    - ANY size fire results in loss of entire cabinet (in this case, loss of all main FW and AFW).
    - Local recovery of AFW was not credited, nor was any other means of feeding the SGs (see responses to RAI questions 8.a, 8.b, and 8.c).
    - ANY size Panel Zone 6 fire was assumed to result in spurious actuation (open) of the SG PORVs, resulting in an MSLB-like plant response (including Instrument Air (IA) to containment valve auto-closure). This requires the operator to re-open IA to containment isolation valves in order to prevent B&F failure (see conservative IA passive accumulator treatment described above).

- CRM Panel fires (LOOP/SBO) (~11% of total fire IPEEE CDF, >5E-6/yr)
  - ANY size fire results in loss of at least one train of offsite and onsite AC power to safeguards equipment.
- CRM Panel Zones 7, 8 and Panel 1PLP (LOCA) (~4% of total fire IPEEE CDF, >2E-6/yr)
  - ANY size fire results in spurious opening of RCS PORVs and block valve failure to operate.

- AFW Pump Room - FA 32 (16.7%, 8.23E-6/yr)
  - Although fire water suppression was credited for certain fires in this fire area, only about 12% of FA 32 CDF involved unsuccessful suppression (1.01E-6/yr, 2.05% of overall fire CDF).
  - Fire water suppression credit was applied using a simple point value (2E-2) taken from EPRI FIVE analysis; PINGP did not have a plant-specific fault tree model for this system (would be expected to provide a lower, more realistic unavailability value).

It is recognized that a re-analysis of internal fires risk, if performed today (based on the current state of knowledge regarding fire risk and methodologies now available), may show that some of the assumptions and methodologies used in the Fire IPEEE were potentially non-conservative. However, it is believed likely that these considerations would not outweigh the scope and magnitude of the conservatisms included in the IPEEE (the most significant of which are described above). Therefore, NSPM believes that it is reasonable to assume that the CDF due to fire would still be comparable to the internal events CDF.

Seismic Events:

In addressing the seismic portion of the IPEEE, a reduced-scope seismic margins assessment was performed in accordance with EPRI NP-6041-SL, "Assessment of Nuclear Power Plant Seismic Margin (Revision 1)." Section F.5.1.7.1 of the Environmental Report stated that there were no identified significant plant vulnerabilities to severe accidents attributable to seismic events at Prairie Island.

Although PINGP does not have a completed seismic PRA, a bounding estimate of seismic risk was developed in support of another NRC submittal. Using a methodology known as the "Simplified Hybrid Method" to quantify the results of a seismic margins analysis (SMA) methodology, a core damage frequency estimate of 7.82E-6/yr was obtained. The purpose of that calculation was only to provide a conservative upper bound estimate of seismic CDF to support that particular submittal, not to obtain a realistic measure of seismic risk at PINGP.

The Simplified Hybrid Method uses only two plant-specific details, the High Confidence Low Probability of Failure (HCLPF) of the seismic Safe Shutdown Equipment List (SSEL) component determined to be the most limiting in the SMA, and the seismic hazard curve for PINGP. Mathematical formulae developed from comparisons of other-plant SMAs and industry seismic PRAs were then used to determine the seismic CDF estimate for PINGP. It is very difficult to conclude much about the true seismic CDF value or distribution of seismic risk based on the results of this simplified method.

However, as calculated, the seismic CDF estimate is below the internal events CDF level currently calculated for either unit. Also, as described in the ER Section F.5.1.6 and in the response to RAI 3.c, plant improvements that lower the risk due to seismic events were made as a result of both the IPEEE and SQUG efforts. Therefore, it is believed that the true seismic CDF is even lower than that calculated by the Simplified Hybrid Method.

Other External Events:

In addition to internal fires and seismic events, the PINGP IPEEE included an assessment of a variety of other external hazards:

- High Winds
- Tornadoes
- External Flooding
- Transportation and Nearby Industrial Facility Accidents
- Other External Hazards

The PINGP IPEEE analysis of these hazards was accomplished by reviewing the plant environs against regulatory requirements regarding these hazards. Based upon this review, it was concluded that PINGP meets the applicable Standard Review Plan requirements and therefore has an acceptably low risk with respect to these hazards. As such, these hazards were determined in the PINGP IPEEE to be negligible contributors to overall plant risk.

Based on the above considerations for internal fires, seismic events, and other external events, the (x2) multiplier was chosen in calculating the value for the Modified Maximum Averted Cost Risk (MMACR). No higher multiplier is believed to be warranted given the current state of knowledge regarding external events at PINGP.

RAI SAMA 3.c

c. As stated in the IPEEE seismic analysis, several potential seismic outliers were dispositioned through an analysis process which determined that the impacted function was not required or could be recovered, or that an alternate means for performing the associated function was available. For those outliers identified in IPEEE Section A.2.4.1.2, where recovery or an alternate means is credited, demonstrate that enhancing the ruggedness of the associated components is not cost-beneficial. The outliers include: turbine-driven AFW pump trip and throttle valves (recovered), diesel generator fuel oil storage tanks 122 and 124 (alternative tanks available), the boric acid transfer pumps (alternate supply available), charging pumps 12 and 23 (alternative charging pumps available), panel 117 (alternate power normally available), cooling water pump 121 (alternate pumps available), condensate storage tanks 11, 12 and 13 (recovered through the use of alternate sources (e.g., cooling water)), component cooling water pressure switches (alternate start signal available), and diesel-driven cooling water pump pressure switches (alternative start signal available). For those outliers stated as being resolved through the closure of USI A-46 (IPEEE Section A.2.4.1.1), confirm that all corrective actions have been completed, and that their use is supported by procedures and training, as appropriate.

NSPM Response to RAI SAMA 3.c

The outliers identified in IPEEE Section A.2.4.1.2, and the discussion of whether increasing their seismic ruggedness would be cost beneficial, are provided in the following table:

IPEEE Seismic Outlier (Section A.2.4.1.2)	IPEEE Disposition Basis	Comments
Turbine Driven Auxiliary Feedwater Pump (TDAFWP) trip and throttle valves	Recovered	From the PINGP seismic hazard curve presented in NUREG-1488 Appendix A, the expected frequency of exceedance of the PINGP SSE (0.12g) is approximately 1E-4/yr. The TDAFWP is seismic category 1 equipment and would be expected to remain available following an SSE event; however, assuming TDAFWP overspeed device is tripped, and 1E-2 probability of random failure of the MDAFWP on the affected unit, the frequency of seismic events requiring recovery of the TDAFWP is at most 1E-6/yr. Identification and recovery of the TDAFWPs is likely in this event (see below). In addition, the cross-tie from the opposite unit MDAFWP may be available, as would RCS bleed and feed capability. Any releases (due to core damage sequences developing from additional unrelated equipment failures) would not be expected to bypass containment. Therefore the potential risk reduction for enhancing the ruggedness of this equipment is not expected to justify the cost. Identification and recovery of a TDAFWP overspeed trip activation following a seismic event is likely due to the numerous cues and procedural guidance available to the operators responding to the event: a) The procedure for visual inspection of equipment and structures after earthquake directs the operator to check local alarms, breakers and protective devices for actuation/trips for horizontal pumps. b) On any reactor trip, procedures direct verification of AFW flow. c) TDAFWP overspeed trip operation is annunciated in the Control Room. For example, for Unit 1, the alarm response procedure directs the operator to determine the cause of the trip, and refers the operator to the procedure for resetting the overspeed trip.
Diesel Generator (DG) Fuel Oil Storage Tanks (FOSTs) 122 and 124	Alternative tanks available	The DG FOSTs are safety-related equipment and the D5 and D6 FOSTs were found to be seismically rugged in the IPEEE as were the Unit 1 and Unit 2 fuel oil transfer pumps and day tanks. The 121 and 123 FOSTs were determined by the SQUG program to be acceptable to SSE levels. Therefore, this equipment would be expected to remain available following an SSE event.

IPEEE Seismic Outlier (Section A.2.4.1.2)	IPEEE Disposition Basis	Comments
		However, assuming the supply from the 122 and 124 tanks had failed due to failure of buried piping (the IPEEE concern), the affected DGs would still operate without operator action for 1 - 2 hours (IPEEE Section A.2.4.1.2). Four safety related storage tanks are provided for supplying fuel oil to the two diesel generator sets D1 and D2. Each tank is equipped with a transfer pump to pump fuel from the tank to the day tank of either DG set. The valve pit contains necessary valving and piping arrangements for transferring fuel oil from any one storage tank to any other tank. Procedures direct the performance of this transfer. Based on the discussion below, the likelihood of successful recovery of the fuel supply through operator action following the event is high. Assuming a 1E-1 probability of failure to restore the fuel oil supply to an affected EDG, and a 1E-1 probability of random failure of the unaffected EDG, the frequency of seismic events requiring recovery of the fuel oil supply to an EDG is at most 1E-6/yr. In addition, the cross-tie from the opposite unit AC buses and EDGs (performed from the Control Room) would be available. Even if the cross-tie failed, only one train of AC power is necessary for successful prevention of core damage. Any releases (due to core damage sequences developing from additional unrelated equipment failures) would not be expected to bypass containment. Therefore the potential risk reduction for enhancing the ruggedness of this equipment is not expected to justify the cost. Identification and recovery of an affected DG fuel oil supply following a seismic event is likely due to the cues and procedural guidance available to the operators responding to the event: a) The procedure for visual inspection of equipment and structures after earthquake directs the operator to check for damage, leaking or flooding from low pressure storage tanks and connected piping, and buried piping. b) Procedures direct the transfer of fuel oil from any Unit 1 DG FOST or the heating boiler FOST.
Boric Acid (BA) transfer pumps	Alternate supply available	At the time of the IPEEE, the ECCS design was such that the initial suction supply for the high head SI pumps was from the Boric Acid Storage Tanks (BASTs). The normal suction supply is now provided by the RWST. The BA transfer pumps' only function credited in the PRA is to supply BA from the BASTs for boration of the RCS following an ATWS event. This is one of a number of potential means of providing long term shutdown of the reactor; its failure probability is dominated by failure of the operator to perform the actions. The overall long term shutdown function contributed to sequences containing less than 1% of the total internal events CDF for either unit, and less than 1/2 of 1% of the total internal events LERF for either unit (i.e., this function did not survive the SAMA Phase 1 screening process described in the ER Sections F.5.1.1 and F.5.1.2). Therefore, the potential

IPEEE Seismic Outlier (Section A.2.4.1.2)	IPEEE Disposition Basis	Comments
		risk reduction for enhancing the ruggedness of this equipment is not expected to justify the cost.
Charging Pumps 13 and 23	Alternative charging pumps available	The availability of individual charging pumps is not a risk significant contributor to the internal events CDF or LERF risk metrics for either unit. No individual charging pump failure basic events survived the SAMA Phase 1 screening process described in the ER (Sections F.5.1.1 and F.5.1.2). Therefore, the potential risk reduction for enhancing the ruggedness of this equipment is not expected to justify the cost.
Panel 117	Alternate power normally available	As stated in the IPEEE report, Section A.2.4.1.2, Panel 117 provides only a backup 120V AC supply function to other normally-energized AC panels. Therefore, the availability of Panel 117 is not a risk significant contributor to the internal events CDF or LERF risk metrics for either unit. No Panel 117 failure basic events survived the SAMA Phase 1 screening process described in the ER Sections F.5.1.1 and F.5.1.2. Therefore, the potential risk reduction for enhancing the ruggedness of this equipment is not expected to justify the cost.
121 Cooling Water (CL) pump	Alternate pumps available	Since the IPEEE was issued, the anchorage and shaft columns of the Diesel Cooling Water Pumps and the 121 Cooling Water Pump have been determined to have HCLPF capacities greater than 0.3g (the IPEEE RLE). Therefore, the potential risk reduction for enhancing the ruggedness of this equipment is not expected to justify the cost.
Condensate Storage Tanks (CSTs) 11, 21 and 22	Recovered through the use of alternate sources (e.g., Cooling Water)	The CSTs are not qualified to the IPEEE RLE of 0.3g, but may survive the SSE. Calculations qualify the 21 and 22 CSTs to the SSE using SQUG methodology. Assuming the CSTs fail on the seismic event, and no operator action occurs to stop the AFW pumps, the pumps will trip automatically on low suction pressure. From the PINGP seismic hazard curve presented in NUREG-1488 Appendix A, the expected frequency of exceedance of the PINGP SSE (0.12g) is approximately 1E-4/yr. The Cooling Water suction supply lines and MOVs to the AFW pumps (MV-32025, MV-32026, MV-32027, and MV-32030) on both units are seismic category 1 equipment and would be expected to remain available following an SSE event, and were found to be seismically rugged to RLE in the IPEEE. These valves are operated from switches located in the control room. Successful operation of only one valve, supplying one AFW pump with suction from the CL system, and restart of the pump is required for successful delivery of AFW to at least one SG. Assuming a 1E-2 probability of operator failure to align at least one AFW pump to its suction supply and restart the pump from the control room, and random failure of the pump of 1E-2, the frequency of seismic events involving an initial loss of heat sink is at most 2E-6/yr (1E-4*(1E-2 + 1E-2) = 2E-6/yr). Identification and recovery of failed pumps is likely in this event due to operator local investigation for equipment damage prompted by procedure (see TDAFWP discussion above). In addition, the cross-tie from the

IPEEE Seismic Outlier (Section A.2.4.1.2)	IPEEE Disposition Basis	Comments
		opposite unit MDAFWP may be available, and RCS bleed and feed capability would remain available. Therefore the frequency of a complete loss of decay heat removal leading to core damage on this event would be less than 1E-7/yr. Any releases (due to core damage sequences developing from additional unrelated equipment failures) would not be expected to bypass containment. Therefore the potential risk reduction for enhancing the ruggedness of this equipment is not expected to justify the cost.
Component Cooling (CC) pressure switches	Alternate start signal available	The CC pump pressure switches are not seismically qualified. Therefore, an automatic start of the standby CC pump (should the running pump fail) may not occur. If the seismic event results in a small LOCA, an SI-signal would be generated that would produce an automatic start signal for the pumps. However, assuming this condition does not exist, in this event the operators would be made aware of the status of the CC system pumps early in the event as the earthquake response procedure directs the operators to verify that at least one CC pump is running. Assuming the running CC pump stops on a seismically-induced loss of offsite power, it will restart following the safeguard 4kV bus load restoration permissive signal. However, a low pressure signal will be required to restart the pump, which may not be received if the pressure switch has failed. If the pump fails to restart, a low flow/pressure condition will occur in the system requiring operator response. From the PINGP seismic hazard curve presented in NUREG-1488 Appendix A, the expected frequency of exceedance the PINGP SSE (0.12g) is approximately 1E-4/yr. Assuming a probability of 1E-2 for the running CC pump failure to start, and that the standby pump pressure switch fails on the seismic event, operator response will be required to restart one pump. A Human Error Probability (HEP) of 1E-2 for operator action to start one CC pump from the control room to restore system pressure is assumed. This results in an expected frequency of loss of all CC pumps of roughly 1E-4*(1E-2 + 1E-2) = 2E-6/yr. However, the charging system will remain available providing cooling to the RCP seals, and preventing loss of RCS inventory. If Cooling Water (CL) is lost to the Unit 1 EDGs, then cross-tie of the Unit 2 4kV power supplies to Unit 1 may be required to prevent RCP seal degradation (this is not an issue for Unit 2 as the Unit 2 EDGs are air-cooled). Assuming another 1E-2 for operator failure to cross-tie the power supplies yields an upper-bound frequency of 2E-8/yr (2E-6*(1E-2) = 2E-8/yr) for core damage due to this event. Any releases (due to core damage sequences developing from additional unrelated equipment failures) would not be expected to bypass containment. Therefore the potential risk reduction for enhancing the ruggedness of this equipment is not expected to justify the cost.

IPEEE Seismic Outlier (Section A.2.4.1.2)	IPEEE Disposition Basis	Comments
Diesel Driven Cooling Water (DDCL) pump pressure switches	Alternative start signal available	The DDCL pump pressure switches are not seismically qualified, but would likely chatter during such an event. Any chattering would likely result in actuation of the diesel-driven pump, a safe condition. Also, if the seismic event results in a small LOCA, an SI-signal would be generated that would produce an automatic start signal for the pumps. However, assuming these conditions do not exist, in this event the operators would be made aware of the condition of the CL system early in the event as managing the CL system flow is a major focus of the procedural response to an earthquake. Assuming the running horizontal motor-driven pumps stop on a seismically-induced loss of offsite power, a low flow/pressure condition will occur in the system requiring operator response. From the PINGP seismic hazard curve presented in NUREG-1488 Appendix A, the expected frequency of exceedance of the PINGP SSE (0.12g) is approximately 1E-4/yr. Assuming that the pressure switches fail on the seismic event, an HEP of 1E-2 for operator action to start 2/3 CL pumps from the control room to restore system pressure is assumed. Combining this with random pump failure probabilities of 1E-2 each results in an expected frequency of loss of all CL pumps of roughly $1E\text{-}4*[(1E\text{-}2) + 3*(1E\text{-}2)^2] = 1E\text{-}6/yr$. In this event, equipment and procedural guidance are available to prevent the loss of CL condition from deteriorating into an RCP seal LOCA condition. At least two charging pumps on each unit would remain available to supply RCP seal injection and seal cooling (only one is required to meet the seal cooling function; however, an operator would have to restart the pump from the control room following the assumed loss of offsite power and load rejection/restoration sequence). Assuming the CL pumps are not eventually restarted, failure of the operator to restore a charging pump could result in an unrecoverable RCP seal LOCA due to the unavailability of CL to support high head injection and recirculation. Note that an SI-signal would be expected to occur on any significant RCP seal LOCA, and would provide the automatic restart of the CL pumps necessary to recover from the event. Assuming no recovery of CL pumps in the short term, and successful operator response to restart charging pumps for RCP seal injection flow, the eventual concern will be loss of heat sink in the SGs (due to loss of CSTs on the seismic event and loss of the backup supply from CL). This condition will drive the operators to a procedure for responding to a loss of secondary heat sink. After all attempts to restore a means of providing secondary heat

IPEEE Seismic Outlier (Section A.2.4.1.2)	IPEEE Disposition Basis	Comments
		removal have failed, the operators are directed to attempt decay heat removal using RCS bleed and feed. However, the first step in this process is to manually actuate SI. This action will start the CL pumps necessary to support bleed and feed cooling and high head recirculation. Applying a 1E-2 probability to this sequence for failure of the operators to perform bleed and feed cooling per the emergency procedures results in an overall core damage frequency of (1E-6)*(1E-2) = 1E-8/yr. Any releases (due to core damage sequences developing from additional unrelated equipment failures) would not be expected to bypass containment (note that induced SGTR sequences developing from this event would have a total frequency of less than 1E-9/yr). Therefore the potential risk reduction for enhancing the ruggedness of this equipment is not expected to justify the cost.

Components listed in Section A.2.4.1.1 of the PINGP IPEEE provide a summary of the SQUG outliers that pertain to the IPEEE scope. In a letter from NRC to Northern States Power dated August 5, 1998, Resolution of Unresolved Safety Issue (USI) A-46 for Prairie Island Nuclear Generating Plant, Units 1 and 2 (TAC NOS. M69474 and M69475), the NRC issued a Safety Evaluation stating that the NRC had received notification that all outliers had been resolved, except for four (4) equipment outliers. The four (4) remaining equipment outliers were committed to be resolved by Prairie Island during the Unit 2 outage in December 1998 and the Unit 1 outage in May 1999. Of those remaining equipment outliers, three (3) were related to components listed in section A.2.4.1.1 of the Prairie Island IPEEE. The equipment included control valves CV-39409, CV-39401, and Motor Control Center MCC-2LA2.

Per Attachment 2 of the letter sent to the NRC from NSP dated November 17, 1997, Response to Request for Additional Information on the Prairie Island Nuclear Generating Plant, Units 1 and 2, Resolution of Unresolved Safety Issue A-46 (TAC Nos. M69474 and M69475), NSP notified the NRC of equipment outliers, resolution descriptions, and resolution timeline, if not already completed. The actions taken to resolve the three outliers are described below and are consistent with statements in the November 17, 1997 letter.

CV-39409

Control valve CV-39409 was identified as an outlier because contact with surrounding conduits could break the solenoid tap connection. The airline to valve CV-39409 was relocated such that the airline is greater than two (2) inches from other electrical conduits in the area. This modification was completed during the 1R20 refueling outage in May of 1999.

CV-39401

Control valve CV-39401 was identified as an outlier because contact with surrounding conduits could break the solenoid tap connection. The airline and associated solenoid valve for CV-39401 were rerouted so that the airline and solenoid valve are a minimum of two (2) inches away from existing conduits. Also, the electrical junction box associated with the solenoid valve for CV-39401 was relocated such that the box is greater than two (2) inches from other electrical conduits in the area. These modifications were completed during the 1R20 refueling outage in May of 1999.

MCC-2LA2
Motor Control Center MCC-2LA2 was identified as an outlier because it was observed that the MCC rocked about its weak axis when bumped, making the welding at the base suspect. New angle support braces were installed at the base of MCC-2LA2 to increase the structural stability of the MCC. This modification was completed during the 2R19 refueling outage in November 1998.

Per the work completed as described above, all outliers identified in Section A.2.4.1.1 of the Prairie Island IPEEE have been resolved. Aside from work completed, no additional procedure changes or training was required to close identified outliers.

RAI SAMA 3.d

d. Discuss the results of the seismic IPEEE from the standpoint of potential SAMAs for the SSCs with the lowest seismic margins, and provide an assessment of whether any SAMAs to increase the seismic capacity of these limiting components would be cost beneficial (i.e., improvements to the component cool water heat exchanger anchorage).

NSPM Response to RAI SAMA 3.d

The seismic IPEEE for PINGP used a seismic margins approach in the identification of vulnerabilities to severe accidents. The focus of the analysis was on determining the survivability of key plant equipment and safety functions, and the assurance of available success paths for safe plant shutdown following the RLE seismic event. Quantitative risk analysis techniques supporting the determination of CDF and LERF risk metrics were not performed. An analysis to quantitatively determine the potential decrease in dose risk to the public from improving the anchorage of the CC heat exchangers is currently not available.

In the initial IPEEE submittal, a 0.12g RLE (the SSE for PINGP) was used as the basis for the seismic margins analysis. In response to the IPEEE seismic RAI questions, the equipment on the Safe Shutdown Equipment List developed for the analysis was reviewed to a 0.3g RLE. The evaluation at the 0.3g RLE concluded that all important safety functions could be accomplished following a seismic event. All of these functions were found to be supported by components with HCLPFs greater than or equal to 0.3g, with the exception of the Component Cooling (CC) heat exchangers. The CC heat exchangers HCLPFs of 0.28g were considered to be very close to the 0.3g threshold, and were thus considered to be adequate. With the exception of the CC heat exchangers (discussed below), based on the IPEEE analysis results and recommendations implemented, it was concluded that there is no benefit to be achieved from evaluation and implementation of additional SAMAs from a seismic risk perspective.

The RLE was assumed to result in the failure of plant systems that are not seismically rugged, such as the equipment supporting delivery of offsite power to the plant, and Instrument and Station Air system equipment. In addition, the analysis assumed the occurrence of a concurrent small LOCA due to the seismic event. This assumption is conservative, because all piping that interfaces with the RCS is considered to be seismically rugged. The Component Cooling (CC) heat exchangers play a key role in the recovery from this postulated set of events. However, even if it is assumed that the RLE results in loss of all four of the CC heat exchangers, equipment remains available to support at least the containment function, such that the dose to the public from any offsite releases from these events are small.

Figure 1 of the IPEEE RAI response for seismic issues[1] shows the success paths available for prevention of core damage following a seismic event according to the IPEEE Seismic Margin Analysis (SMA) methodology. If it is assumed that the CC heat exchanger function is failed on the seismic event, then the CC system function shown in the diagram is assumed to be failed. Although from the diagram it may appear that the CC function is required for success for both paths shown, this is not the case for the loss of offsite power (LOOP) success path. In this case, core damage is prevented as AC power (through the onsite emergency diesel generator supply), DC power, Cooling Water (CL), Reactor Protection (RPS) and Control Rods, RCP seal injection through the Chemical and Volume Control System (CVCS) charging pumps, and the Auxiliary Feedwater (AFW) system remain available. The CC function, which is to provide cooling to the RCP seals, is accomplished by the CVCS System.

If a Small LOCA is conservatively assumed to occur with the seismic event, then core damage will be assumed to occur, because the remaining functions shown on the diagram all depend on the CC function. Ultimately, this dependency comes from the requirement for a CC supply to the SI pump oil coolers and the RHR heat exchangers. However, even in this case, the capability for RCS depressurization and RWST injection with the RHR pumps remains available, such that the potential for early core damage and vessel failure at high pressure is low. Also, the containment fan coil units remain available for long term containment pressure control. Therefore, the potential for significant offsite releases (early or late) from success paths that require the CC function is low.

As described above, an analysis to quantitatively determine the potential decrease in dose risk to the public from improving the anchorage of the CC heat exchangers is not available. While the existing anchorage of the CC heat exchangers does not ensure the survivability of these components at the 0.3g RLE, it is very close (0.28g). Assumption of failure of all CC heat exchangers at the RLE is conservative. Also, simplifying and bounding assumptions made in the IPEEE seismic margins analysis, such as the assumption of a concurrent LOOP, loss of instrument air and small LOCA on occurrence of the RLE, are conservative. Each of these assumed events would individually have a conditional probability of occurrence below 1.0; the conditional probability of all of these events occurring would be significantly lower. In addition, as the charging function remains available, the small LOCA of concern in this event would be one involving leakage greater than available charging pump makeup. Given the seismic capability of RCS equipment, piping and piping connected to the RCS, a small LOCA of this size occurring following a seismic event is clearly not a certainty, even at the RLE.

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[1] Letter from NSP to NRC dated February 28, 2000, "Response to Request for Additional Information Regarding Report NSPLMI-96001, Individual Plant Examination of External Events (IPEEE), Related to Generic Letter 88-20" (ML003691712).

A plant modification to improve the anchorage of the CC heat exchangers to withstand higher level seismic events would be expensive (estimates for a similar project from another recent License Renewal applicant's Environmental Report indicate the costs could exceed $500 K).

Based on the above considerations, it is concluded that the averted dose benefit achieved from this proposed modification would not exceed its estimated implementation cost.

RAI SAMA 4

ER Section F.3.5 indicates that the core radionuclide inventory used in the MACCS2 analysis is based on results of a plant-specific calculation assuming a core average exposure of 50,000 MWD/MTU, combined with core inventory information from MACCS2 Sample Problem A adjusted to account for the PINGP power level. Describe the plant specific calculation (which appears to be in addition to the calculation described in the updated safety analysis report (USAR)). Describe the purpose and development of the additional adjustment factor of 1.39 (based on differences between the PINGP USAR calculation and MACCS2 Sample Problem A values). Confirm that the resulting core inventory reflects the PINGP-specific fuel burnup/management as the plant is expected to be operated during the renewal period, including any planned fuel management changes (power uprates, extended burnup fuel, etc.).

NSPM Response to RAI SAMA 4

As discussed in ER Section F.3.5, MACCS2 requires input for 60 nuclides. These 60 nuclides are listed in Table F.3-3. Plant specific core inventory values for 20 significant nuclides (including the Cs and I nuclides) required by MACCS2 were available from data contained in the USAR. For the remaining 40 core inventory nuclides, plant specific estimates were judged to be required.

In some past SAMA evaluations, the MACCS2 Sample Problem A core inventory values were utilized in lieu of plant specific core inventories. For those studies, the MACCS2 Sample Problem A core inventories were adjusted by using a ratio to account for differences between the Sample Problem A core power level and the SAMA plant specific power level. It has become recognized that in addition to differences in core power levels, changes in fuel enrichment and core exposure between current industry practices and those assumed for Sample Problem A should be accounted for via a plant specific core inventory.

Since a Prairie Island plant specific core inventory for 40 of the 60 nuclides was not available, plant specific values for the 40 nuclides were estimated in the following manner:

1. The 60 MACCS2 Sample Problem A core inventory values were adjusted to account for differences between the Sample Problem A power level of 3412 MW_{th} and the Prairie Island power level of 1650 MW_{th}.
2. For each of the 20 nuclide values contained in the USAR, a comparison was made between the USAR value and the adjusted Sample Problem A value. The difference between the USAR nuclide value and the adjusted Sample Problem A value differed for each nuclide.
3. The average change between the USAR values and the adjusted Sample Problem A values was calculated for these 20 nuclide values. On average, the USAR nuclide values were approximately 39 percent higher than the adjusted Sample Problem A values.
4. This factor of 1.39 was then applied to the 40 adjusted Sample Problem A values to estimate the plant specific core inventory of these 40 nuclides.

The increase factor of 1.39 that was applied to the 40 adjusted Sample Problem A values was judged to adequately estimate the impacts associated with fuel enrichment and core exposure between the Sample Problem A core assumptions and those utilized by Prairie Island.

Although the change in core average exposure and fuel burnup strategies that make use of newer and more efficient fuel designs will have an impact on the radioisotopic source term, specific operating strategies and power uprates planned for the future are not fully realized at present. To capture this and other inherent uncertainties that are part of the SAMA methodology, the use of the 95th percentile averted cost risk results for each Phase 2 SAMA was used to determine whether a particular SAMA was cost beneficial. The 95th percentile results were meant to provide a "bounding" assessment to determine those SAMAs that may be cost beneficial and worthy of a more detailed analysis via the utility's action tracking process for plant modifications.