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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549-4561

DIVISION OF
CORPORATION FINANCE

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Received SEC

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Washington, DC 20549

February 27, 2012

Scott Wilensky
Xcel Energy Inc.
scott.wilensky@xcelenergy.com

Act: 1934
Section:
Rule: 14a-8
Public
Availability: 2-27-12

Re: Xcel Energy Inc.

Dear Mr. Wilensky:

This is in regard to your letter dated February 24, 2012 concerning the shareholder proposal submitted by the New York State Common Retirement Fund for inclusion in Xcel Energy's proxy materials for its upcoming annual meeting of security holders. Your letter indicates that the proponent has withdrawn the proposal, and that Xcel Energy therefore withdraws its January 13, 2012 request for a no-action letter from the Division. Because the matter is now moot, we will have no further comment.

Copies of all of the correspondence related to this matter will be made available on our website at http://www.sec.gov/divisions/corpfin/cf-noaction/14a-8.shtml. For your reference, a brief discussion of the Division's informal procedures regarding shareholder proposals is also available at the same website address.

Sincerely,

Matt S. McNair
Attorney-Adviser

cc: Patrick Doherty
State of New York Office of the State Comptroller
Pension Investments & Cash Management
633 Third Avenue-31st Floor
New York, NY 10017

Xcel Energy®
RESPONSIBLE BY NATURE®

Scott Wilensky
Senior Vice President and General Counsel

414 Nicollet Mall, 5th Floor
Minneapolis, Minnesota 55401
Phone: 612.330.5942
Fax: 612.215.4504

February 24, 2012

Office of the Chief Counsel
Division of Corporation Finance
U.S. Securities and Exchange Commission
100 F. Street, N.E.
Washington, D.C. 20549

BY E-MAIL

Re: Xcel Energy Inc. – Withdrawal of No Action Request Regarding Shareholder Proposal of the State of New York Office of the State Comptroller

Dear Ladies and Gentlemen:

On January 13, 2012, Xcel Energy Inc. (the "Company"), submitted a letter requesting that the Staff of the Division of Corporation Finance (the "Staff") confirm that it would not recommend to the Securities and Exchange Commission that enforcement action be taken if the Company excluded from its proxy materials for its 2012 Annual Meeting of Shareholders scheduled for May 16, 2012 (the "2012 Proxy Materials") a shareholder proposal (the "Proposal") from the State of New York Office of the State Comptroller (the "Proponent").

Attached hereto as Exhibit A is a letter from the Proponent dated February 24, 2012 voluntarily withdrawing the Proposal. In reliance on this letter, the Company hereby withdraws its request for a no action letter from the Staff relating to relating to the Company's ability to exclude the Proposal from its 2012 Proxy Materials pursuant to Rule 14a-8 under the Securities Exchange Act of 1934.

A copy of this letter is being provided to the Proponent. If the Staff has any questions with respect to the foregoing, please contact Wendy Mahling by telephone at 612-215-4681 or by email at wendy.b.mahling@xcelenergy.com.

Best Regards,

Scott Wilensky
Senior Vice President and General Counsel
Xcel Energy Inc.

cc: Patrick Doherty
Director, Corporate Governance
State of New York Office of the State Comptroller
633 Third Avenue, 31st Floor
New York, New York 10017

Exhibit A

Copy of the Withdrawal Letter

X cc: [illegible]

State of New York
OFFICE OF THE STATE COMPTROLLER

Patrick Doherty
Director - Corporate Governance
633 Third Avenue – 31st Floor
New York, NY 10017

Tel- (212) 681-4823
Fax- (212) 681-4468

To: [illegible] Hart

Phone Number: 812-215-5386

Fax Number: ~~812-330-5878~~ 318-4794

Date: 2/24/12

Pages ~~to follow~~: 2

Message:

THOMAS P. DINAPOLI
STATE COMPTROLLER

STATE OF NEW YORK
OFFICE OF THE STATE COMPTROLLER

PENSION INVESTMENTS
& CASH MANAGEMENT
633 Third Avenue-31st Floor
New York, NY 10017
Tel: (212) 681-4489
Fax: (212) 681-4468

February 24, 2012

Ms. Cathy Hart
Corporate Secretary
Xcel Energy Inc.
414 Nicollet Mall, Suite 500
Minneapolis, Minnesota 55401-1993

Dear Ms.Hart:

On the basis of the information you provided to us and our subsequent discussions, I hereby withdraw the resolution on nuclear power safety filed with your company by the Office of the State Comptroller on behalf of the New York State Common Retirement Fund. We look forward to further discussions with you concerning this important issue.

Very truly yours,

Patrick Doherty
pd:jm
Enclosures

Xcel Energy®
RESPONSIBLE BY NATURE®

Scott Wilensky
Senior Vice President and General Counsel

414 Nicollet Mall, 5th Floor
Minneapolis, Minnesota 55401
Phone: 612.330.5942
Fax: 612.215.4504

January 13, 2012

Office of the Chief Counsel
Division of Corporation Finance
U.S. Securities and Exchange Commission
100 F. Street, N.E.
Washington, D.C. 20549

BY E-MAIL

Re: Xcel Energy Inc. – Notice of Intent to Exclude from Proxy Materials Shareholder Proposal of the State of New York Office of the State Comptroller

Dear Ladies and Gentlemen:

This letter is submitted on behalf of Xcel Energy Inc., a Minnesota corporation ("Xcel Energy"), pursuant to Rule 14a-8(j) under the Securities Exchange Act of 1934, to notify the Securities and Exchange Commission (the "Commission") of Xcel Energy's intention to exclude from its proxy materials for its 2012 Annual Meeting of Shareholders scheduled for May 16, 2012 (the "2012 Proxy Materials") a shareholder proposal (the "Proposal") from the State of New York Office of the State Comptroller (the "Proponent"). Xcel Energy requests confirmation that the staff of the Division of Corporation Finance (the "Staff") will not recommend an enforcement action to the Commission if Xcel Energy excludes the Proposal from its 2012 Proxy Materials in reliance on Rule 14a-8.

Pursuant to Rule 14a-8(j) and *Staff Legal Bulletin No. 14D* (November 7, 2008), we have submitted this letter and its attachments to the Commission via e-mail at shareholderproposals@sec.gov. A copy of this submission is being sent simultaneously to the Proponent as notification of Xcel Energy's intention to exclude the Proposal from its 2012 Proxy Materials. We would also be happy to provide you with a copy of each of the no-action letters referenced herein on a supplemental basis per your request.

Xcel Energy intends to file its 2012 Proxy Materials on or about April 2, 2012.

The Proposal

Xcel Energy received the Proposal on December 7, 2011. A full copy of the Proposal is attached hereto as Exhibit A. The Proposal reads as follows:

WHEREAS, the Fukushima nuclear crisis in Japan, brought on by an earthquake and tsunami, and the August, 2011 earthquake on the US east coast, have drawn increased attention to issues related to nuclear power safety, and

WHEREAS, Xcel Energy currently owns and operates two nuclear power plants in the state of Minnesota, and

WHEREAS, independent studies have indicated that nuclear power plants continue to experience problems with safety-related equipment and worker errors that increase the risk of damage to the reactor cores, and that recognized but misdiagnosed or unresolved problems often cause significant events at nuclear plants, or increase their severity, and

WHEREAS, a March, 2011 report by the Union of Concerned Scientists analyzed a series of U.S. reactor incidents in 2010 that prompted special intervention by the Nuclear Regulatory Commission ("NRC"). The report found that these events were caused by a variety of shortcomings such as "inadequate training, faulty maintenance, poor design, and failure to investigate problems thoroughly (Union of Concerned Scientists, <u>The NRC and Nuclear Power Plant Safety in 2010: A Brighter Spotlight Needed</u> (2011)), <u>http://www.ucsusa.org/assets/documents/nuclear_power/nrc-2010-full-report.pdf</u>, and

WHEREAS, this report recommends that companies operating nuclear plants adopt enhanced safety measures, including transferring spent nuclear fuel from storage pools to dry casks once it has cooled, and that companies comply fully with fire protection regulations issued by the NRC in 1980 and 2004 – recommendations which could help to reduce the plants' vulnerabilities in the event of an earthquake or other significant event, and

WHEREAS, following the August, 2011 earthquake on the U.S. east coast, the Wall Street Journal reported that U.S. regulators have concluded that "more seismic activity is now considered possible in the U.S. than had been understood when older plants were built", [sic] ("Nuclear Site Status Checked" <u>Wall Street Journal</u> 8 Aug. 2011), and that a number of U.S. plants were now threatened by tremors greater than they were designed to withstand. (Dominion Resource's North Anna Power Station in Virginia, located 10 miles from the epicenter of the August 23,2011 [sic] 5.8 magnitude earthquake, lost normal grid power and was shut down for several months),

THEREFORE, be it resolved that shareholders request that a committee of Independent directors be appointed to conduct a special review of the company's nuclear safety policies and practices in light of the extraordinary developments and findings described above, including potential risks associated with seismic events in and around the company's nuclear power plants, and that that committee report to shareholders on its findings at reasonable expense and excluding proprietary or confidential information.

<u>Bases for Exclusion</u>

A. The Proposal May Be Excluded Pursuant to Rule 14a-8(i)(10) as Xcel Energy Has Already "Substantially Implemented" It.

Rule 14a-8(i)(10) provides that a company may exclude a proposal from its proxy materials if "the company has already substantially implemented the proposal." The Commission adopted the current version of this exclusion in 1983, and since then it has regularly concurred that when a company can demonstrate that it has addressed each element of a proposal, that proposal may be excluded. Moreover, the company need not have implemented each element in the precise manner suggested by the proponent. *Release No. 34-20091* (August 16, 1983). Rather, the actions taken by the company must have addressed the proposal's "essential objectives." *See Anheuser-Busch Companies, Inc.* (January 17, 2007). The Staff has articulated this standard differently by stating that "a determination that the company has substantially implemented the proposal depends upon whether the particular policies, practices and procedures *compare favorably* with the guidelines of the proposal." *Texaco, Inc.* (March 28, 1991) (emphasis added).

In this case, it is clear that Xcel Energy has already "substantially implemented" the Proposal and that it may therefore be excluded pursuant to Rule 14a-8(i)(10). The Proposal can be characterized as requesting three "essential objectives": (1) that Xcel Energy appoint a committee of "Independent directors"; (ii) that this committee "conduct a special review of the company's nuclear safety policies and practices in light of the extraordinary developments and findings described [in the Proposal's supporting statement], including potential risks associated with seismic events in and around the company's nuclear plants"; and (3) that the committee report to shareholders on its findings. As discussed below, the actions that Xcel Energy has already taken with respect to these matters "compare favorably" with the Proposal and Xcel Energy's exclusion of the Proposal pursuant to Rule 14a-8(i)(10) is therefore warranted.

1. Appointment of a Committee of Independent Directors

The Proposal calls for the appointment of a committee of independent directors to be given authority with respect to certain nuclear matters. As shown below, Xcel Energy already has in place such a committee. Since at least 1994, Xcel Energy has maintained a Board committee dedicated to the safety of its nuclear power plants. The current committee—the Nuclear, Environmental and Safety Committee (the "Nuclear Committee")—is comprised entirely of independent directors and is responsible for providing oversight of Xcel Energy's nuclear operations. The Nuclear Committee Charter is attached hereto as Exhibit B. As described in the proxy statement for Xcel Energy's 2011 Annual Meeting of Shareholders, the Nuclear Committee is responsible for, among other things:

- Oversight of nuclear strategy and operations, including the review of the results of reports and major inspections and evaluations;
- Review of environmental strategy, compliance, performance issues, and initiatives;
- Review of material risks relating to Xcel Energy's nuclear operations and its environmental and safety performance, including risks to Xcel Energy's reputation; and
- Review of safety performance, strategy, and initiatives.

In addition, Xcel Energy also has a Nuclear Oversight Committee that is comprised of three independent nuclear experts who are not employees of Xcel Energy and is responsible for providing a high-level review of the Monticello Nuclear Generating Plant ("Monticello") and the Prairie Island Nuclear Generating Plant ("Prairie Island")—Xcel Energy's two operating nuclear plants. The Nuclear Oversight Committee is composed of subcommittees that look at operational excellence, organizational excellence, training excellence and equipment excellence. The Nuclear Operating

Committee uses this information to form their findings and reports on its findings to our Chief Nuclear Officer and, at least annually, to the Nuclear Committee. Therefore, the already-existing Nuclear Committee, which met four times in 2011, and the Nuclear Oversight Committee, go beyond the committee called for by the first element of the Proposal.

2. Review of Xcel Energy's Nuclear Safety Policies and Practices

The Proposal requests that the committee to be appointed "conduct a special review of the company's nuclear safety policies and practices." Reviewing the company's "nuclear safety policies and practices," however, is precisely what the Nuclear Committee already does. As stated in the Nuclear Committee's Charter, the committee is tasked with assisting

> the Board of Directors in oversight of the nuclear strategy and nuclear operations of the Company and its subsidiaries . . . and safety performance. In performing this function, the Committee members will provide advice to the Chief Executive Officer and senior executives *and will review appropriate issues such as nuclear plant performance, safety and compliance [and] safety aspects of operations* (emphasis added).

The Charter mandates that the Nuclear Committee shall:

- Provide oversight of Xcel Energy's nuclear strategy and operations, including a review of the results of major inspections and evaluations by external oversight and regulatory bodies, and reports of the independent Nuclear Oversight Committee;
- Review the Company's safety performance and safety strategy and initiatives;
- Review of material risks relating to Xcel Energy's nuclear operations and safety performance; and
- Review the state of the nuclear industry.

The Nuclear Committee meets on a regular basis, including four times during 2011, and receives regular updates on plant and industry issues. In addition, it has unlimited access to plant and regulatory information and there are no limits on its ability to request information or request that an investigation be performed on any topic.

In response to the earthquake, tsunami, and resulting accident at Fukushima Daiichi Nuclear Station, Xcel Energy engaged in an evaluation of the operations and systems at its nuclear plants. The steps taken by Xcel Energy include the following:

- Design changes at both Monticello and Prairie Island to reduce the potential for core damage from an internal flooding hazard;
- Seismic assessments performed by an outside contractor, Stevenson & Associates, of important plant features used to respond to such hazards seen during the Fukushima disaster;
- Walkthroughs, tests, and performance of key emergency procedures to ensure they can be executed effectively when needed;
- Inventories, tests, and assessments of equipment needed for key emergency procedures to ensure equipment is staged and ready to use;

- Acquisition of additional portable water pumps to be used to cool the reactors and fuel pools in the event of a catastrophe;
- Collaboration with other nuclear plant owners to develop regional response centers to augment the capabilities of both the Monticello and Prairie Island plants in the event of a catastrophe; and
- Improvement of our capability to respond to extended station blackout events caused by an earthquake.

The steps that were taken are designed to minimize the risk of loss of continuous power and response capability for any form of natural disaster, which for our plants has typically been tornadoes.

In furtherance of that evaluation, in May of 2011, Xcel Energy, in cooperation with the U.S. Nuclear Regulatory Commission (the "NRC"), participated in an assessment of the emergency preparedness capabilities of both the Monticello and Prairie Island plants. That review consisted of the following procedures, among others:

- Verify through test or inspection that equipment is available and functional;
- Verify through walkdowns or demonstration that procedures to implement the emergency strategies are in place and executable;
- Verify the training qualifications of operators and the support staff needed to implement the procedures and that work instructions are current for activities related to security issues and severe accident management guidelines; and
- Verify through walkdowns and inspection that all required materials are adequate and properly staged, tested, and maintained.

Of particular note, during the Prairie Island Nuclear Generating Plant inspection,

> Industry seismic experts conducted walkdowns of fire and flood mitigating [structures, systems, or components] to determine whether this equipment would remain available following a safe shutdown earthquake. Seismic vulnerabilities, including storage locations, were identified, along with mitigating strategies for equipment that was not seismically qualified.

Xcel Energy's Monticello and Prairie Island plants are in full compliance with NRC Fire Protection regulations referenced in the Proposal and Prairie Island is in the process of implementing NFPA 805. In addition, we regularly evaluate and provide data regarding safety system performance to the NRC, perform self-inspections, and identify to the NRC any self-identified findings.

Xcel Energy's efforts in reviewing and maintaining functioning safety equipment and procedures are longstanding and ongoing. Xcel Energy and its Nuclear Committee continuously review the company's nuclear operations, which are routinely reported, either internally or publicly. These continuous reviews form the basis for Xcel Energy's nuclear safety-related disclosures to the public. Regarding the concerns identified in the findings (problems with safety related equipment and worker errors, spent fuel pool transfer to dry storage, full compliance with fire protection requirements, and updated seismic information), Xcel Energy has undertaken review of these issues and no specific problems were noted concerning either Monticello or Prairie Island, and the information presented by Xcel Energy confirms compliance with present NRC regulations and will continue to comply with new NRC regulations as required.

3. Disclosure Regarding Nuclear Safety Issues

The Proposal requests a "report" to be issued by the requested committee on its "findings." However, Xcel Energy already makes a substantial amount of information regarding its nuclear operations available to the public. This information is provided through various different mediums, including Xcel Energy's website, which contains numerous documents on such varied topics as the basic operation of Xcel Energy's Monticello and Prairie Island power plants, to nuclear emergency information and preparedness, to the company's Emergency Action Level Manuals; links to the NRC's website, which includes reports on such topics as Xcel Energy's response to the Fukushima disaster, to security baseline inspections, to risk assessments of Xcel Energy's nuclear operations; investor-related calls and road shows directed at, in part, shareholders of the company, the proposed recipients of the report requested in the Proposal; and Xcel Energy's periodic reports filed with the Commission.

Xcel Energy maintains its own website through which shareholders and the general public may access information about the company's nuclear power plants. An overview of Xcel Energy's nuclear site can be found at: http://www.xcelenergy.com/Safety_&_Education/Nuclear_Safety/About_Nuclear_Energy/Nuclear_Power. In the "Nuclear Safety" section of the site, Xcel Energy makes clear that it has "an established and tested plan," and then briefly outlines what that plan is. In the "Nuclear Emergency" segment of the site, Xcel Energy states that "there is no higher priority than operating our power plants safely." In addition, in the "Nuclear Power at Xcel Energy" segment, Xcel Energy provides a Prairie Island License Renewal memorandum that emphasizes the safety of its nuclear plants and the nuclear industry generally:

> The NRC subjects nuclear power to a rigorous program of oversight, inspection, preventive and corrective maintenance, equipment replacement and equipment testing. These programs ensure nuclear plant equipment continues to meet safety standards, no matter how long a plant has been operating.

Further, under the "Nuclear Emergency Preparedness" section, Xcel Energy provides basic information on what to do if sirens sound, where to go if the public is told to evacuate, and where school children should be taken in the remote chance of an emergency. This section also makes publicly available the Emergency Action Level Manuals for both the Monticello and Prairie Island plants. The Manuals, in part, are designed to lend to the understanding of what a particular condition or event means in order to provide emergency workers at the various off-site agencies a clear idea of the correct response to the condition or event. The Manuals also provide a review and guidance on such varied topics as abnormal radiological levels, a cold shutdown or a refueling system malfunction, events related to a malfunction of the Independent Spent Fuel Storage Installation system, and hazards and other conditions that may affect plant safety, amongst others. More specifically, the Manuals provide descriptions of hazards and other conditions affecting plant safety.

Xcel Energy has also included a discussion of its nuclear power plants and the regulation to which they are subject in its quarterly reports on Form 10-Q. In Xcel Energy's Form 10-Q for the quarter ended September 30, 2011, for example, it noted the "event that occurred at the nuclear plant in Fukushima, Japan" and the "impact the NRC's deliberations" could have on the company. Xcel Energy also discussed the July 12, 2011 NRC task force report, "which confirm[ed] the safety of U.S. nuclear energy facilities and recommend[ed] actions to enhance U.S. nuclear plant readiness to safely manage severe events." To better coordinate response activities to the report, Xcel Energy further commented that "the U.S. nuclear energy industry has created a steering committee made up of representatives from major electric sector organizations to integrate and coordinate the industry's ongoing responses" to the Fukushima disaster, of which Dennis Koehl, Xcel Energy's Senior Vice President and Chief Nuclear Officer, is a member.

In addition, outside of its own website, Xcel Energy has a multitude of risk assessments and evaluations of its own plants available to the general public. The following four instances provide examples of some. First, in May of 2011, Xcel Energy, in cooperation with the NRC, participated in an inspection of and prepared reports pertaining to both Monticello and Prairie Island in order "to promptly assess the capabilities of [the plants] to respond to extraordinary consequences similar to those that have recently occurred at the Japanese Fukushima Daiichi Nuclear Station." These reports are publicly available at http://adams.nrc.gov/wba and are attached hereto as Exhibit C-1 and Exhibit C-2, respectively. The reports describe in detail the actions taken by the plant operator, the actions taken by the inspector, and the general results of the tests. Links to the NRC website and the ADAMS database are located on the Xcel Energy website.

Second, in May of 2011, Xcel Energy discussed its nuclear safety and operations at both the West Coast Road Show on May 9-11 and the Deutsche Bank road show on May 11. The relevant slides are attached hereto as Exhibit D. In the slides, Xcel Energy discussed and described the multiple safety systems that the Monticello and Prairie Island nuclear plants have and how they operate. For instance, Xcel Energy noted that "Monticello has eight ways to get water into the core in an emergency" and that "Prairie Island has nine independent ways to get water into the cores in an emergency."

Third, in April of 2011, Xcel Energy completed its First Quarter 2011 Earnings conference call. The transcript of the call is attached hereto as Exhibit E. During the call, Benjamin Fowke, Xcel Energy's then-President and Chief Operating Officer, spoke about the "safety of [Xcel Energy's] nuclear fleet" and Xcel Energy's response to the events at the Fukushima nuclear plant. In discussing Xcel Energy's safety measures after Fukushima, Mr. Fowke stated the following:

> In response to the recent events at Fukushima nuclear plants . . . our Prairie Island and Monticello plants have assessed their capabilities to maintain safety in the face of severe adverse events, including the loss of significant operational and safety systems. Nuclear power plants are built to withstand environmental hazards, including earthquakes, hurricanes, tornadoes and floods. Even plants like ours that our located outside of areas with extensive seismic activity are designed for safety in the event of such a natural disaster.
>
> If either of our plants experienced an adverse event, our normal safety systems would keep the reactor core cool. We have two diesel generators for each unit, each one capable of supplying power to meet all the safety related needs for that unit should the plant be disconnected from the power grid. In addition, our fuel tanks are stored and

> sealed below ground which protects them from natural disasters. Should diesel generators fail, our facilities are equipped with battery back-up systems. In addition, we have pumps that are driven by steam turbines that do not depend on electricity. In the unlikely event that none of the normal and backup safety systems were available to keep the reactor core cool, we have portable pumps that could be hooked up to supply cooling water into the reactor from the Mississippi River.

Mr. Fowke went on to note that "there are always lessons learned from a disaster," and Xcel Energy's participation in an industry working group designed to better understand "the events that occurred at Fukushima" and to recommend "actions to improve the ability of U.S. plants to withstand similar events" will help towards that end.

Fourth, in November of 2009, Xcel Energy had a report prepared by a consultant titled "Monticello MELLA+ Risk Assessment," which is attached hereto as Exhibit F and is publicly available at http://adams.nrc.gov/wba. The scope of the report "includes assessment of the risk impacts due to internal events (including internal flooding scenarios)." Moreover, the report provides findings on the significance of fire induced risks, seismic risks, other external hazards (including tornadoes, external floods, transportation accidents, and other external hazards), and shutdown risks.

In addition to the foregoing examples, Xcel Energy has also addressed, at both Monticello and Prairie Island, the recommendations of the report by the Union of Concerned Scientists concerning spent nuclear fuel and fire protection regulations referenced in the Proposal's supporting statement. With regard to spent nuclear fuel, the Prairie Island Emergency Action Level Manual outlines Xcel Energy's procedure for transferring spent nuclear fuel from storage pools to dry casks once it has cooled:

> Used *fuel assemblies* (groups of metal rods containing irradiated uranium fuel pellets) are stored in the plant's *spent fuel pool* once they are removed from the *reactor vessel*. These used fuel assemblies are stored under water to cool them since *decay heat* is being generated by the highly radioactive *fission products* within them. Once they have been stored in the spent fuel pool for a long enough time, however, the decay heat drops to a point where storing them under water is no longer necessary. The used fuel assemblies can then be transferred to sealed steel containers (fuel cask).

Concerning the NRC's fire protection regulations, Xcel Energy's nuclear power plants are both in full compliance with all fire protection regulations in 10 C.F.R. Part 50, Section 50.48 and Appendix R to 10 C.F.R. Part 50. Further, Prairie Island is currently in the process of implementing National Fire Protection Association Regulation 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," which was recently endorsed by the NRC.

A recent no-action letter, *Exxon Mobil* (March 17, 2011), provides strong support for the exclusion of the Proposal under Rule 14a-8(i)(10). In *Exxon Mobil*, the Staff concurred with the company's argument that its pre-existing policies and procedures achieved the essential objectives of the proposal at issue and thus compared favorably with the proposal's guidelines. In that matter, the proposal asked that the company inspect its safety processes in light of ongoing concerns, describe the board's oversight of safety management, and report on the steps the company had taken to address those concerns. The company, in addressing the proposal's mandates, presented publications it had made publicly available that reported on the company's safety processes, like Xcel Energy, via a number of different mediums: the company website, corporate reports, executive speeches, and the like. In light of that presentation, the Commission concurred with the exclusion of the proposal, stating: "Based on the information you have presented, it appears that Exxon Mobil's public disclosures compare favorably with the guidelines of the proposal and that Exxon Mobil has, therefore, substantially implemented the proposal." Xcel Energy's disclosure, akin to Exxon Mobil's in the matter just described, addresses the "essential objectives" of the Proposal: (1) Xcel Energy already has a committee of independent directors (2) who review the full range of nuclear safety issues, and (3) Xcel Energy has adequate public disclosure regarding nuclear safety issues that affect the company, its nuclear power plants, and the public.

As the foregoing provides, Xcel Energy has an existing committee of independent directors who review the company's nuclear safety policies and practices, and those reviews are made available for review by the public. The very concerns raised by the Proposal have been reviewed, addressed, and reported on by Xcel Energy and its Nuclear Committee. Accordingly, for the reasons stated above and in accordance with Rule 14a-8(i)(10), the Company believes the Proposal may be excluded from its 2012 Proxy Materials.

B. The Proposal May Be Excluded Pursuant to Rule 14a-8(i)(7) Because It Deals With Matters Relating to the Company's Ordinary Business Operations.

Xcel Energy believes that it may exclude the Proposal because it relates to Xcel Energy's ordinary business operations and does not rise to the level of "significant social policy issue." Xcel Energy continually reviews and monitors the operations at its nuclear plants and the extremely intricate and detailed nuclear regulations with which it is required to comply. In addition, Xcel Energy's nuclear plants are both located in Minnesota, an area not at risk of seismic events akin to Fukushima, Japan or even Virginia. Moreover, it is not clear what Xcel Energy would do differently if the Proposal were adopted, both because the company has already substantially implemented the Proposal's objectives, as discussed above, and since the monitoring and evaluation of its nuclear operations is something that has been a part of Xcel Energy's ordinary business matters for years.

Rule 14a-8(i)(7) permits a company to exclude a shareholder proposal dealing with matters relating to a company's "ordinary business" operations. According to the Commission, the term "ordinary business" refers to matters that are not necessarily "ordinary" in the common meaning of the word; rather, "ordinary business" is understood as being "rooted in the corporate law concept providing management with the flexibility in directing certain core matters involving the company's business and operations." *Release No. 34-40018* (May 21, 1998). The Commission has explained that this exclusion rests on two central considerations: first, that "[c]ertain tasks are so fundamental to management's ability to run a company on a day-to-day basis that they could not, as a practical matter, be subject to direct shareholder oversight," and second, the degree to which the proposal attempts to "micromanage" a company by "probing too deeply into matters of a complex nature upon which shareholders, as a group, would not be in a position to make an informed judgment." *Id.* (citing *Release No. 34-12999* (November 22, 1976)).

When examining whether a proposal may be excluded under the Commission's "ordinary business" standard, the first step is to determine whether the proposal raises any significant social policy issue. If a proposal does not raise such an issue, then the company may exclude it under Rule

14a-8(i)(7). However, if a proposal does raise a significant social policy issue, that is not necessarily the end of the analysis. Rather, the Staff has concurred with the exclusion of shareholder proposals that raise a significant social policy issue when other aspects of the proposal implicate a company's ordinary business.

The Commission has noted that certain topics related to nuclear power may present a significant social policy issue. For instance, in *Release No. 34-12999*, the Commission stated the following:

> [A] proposal that a utility company not construct a proposed nuclear power plant has in the past been considered excludable under former subparagraph (c)(5). In retrospect, however, it seems apparent that the economic and safety considerations attendant to nuclear power plants are of such magnitude that a determination whether to construct one is not an "ordinary" business matter.

See also, e.g., Dominion Resources, Inc. (February 9, 2011) (reaffirming *Release No.34-12999* by denying no-action relief with regard to a proposal concerning the "costs and risks of new nuclear construction"); *Northern States Power Co.* (February 9, 1998) (declining to provide no-action relief with regard to a shareholder proposal that addressed the conversion of a nuclear power plant into a natural gas plant); *Florida Progress Corp.* (January 26, 1993) (declining to concur with the exclusion of a shareholder proposal requesting a report providing data—concerning costs, malfunctions, deaths, accidents, and the like—on the operation and safety of a particular nuclear power plant).

The Staff has commented that the inclusion or exclusion of a shareholder proposal does not turn solely on its general subject matter, but rather on the precise language of the proposal and what it seeks, as well as the arguments the company makes with respect to why the proposal should be excluded from its proxy materials. In the Staff's own words:

> **6. Do we base our determinations solely on the subject matter of the proposal?** No. We consider the specific arguments asserted by the company and the shareholder, the way in which the proposal is drafted and how the arguments and our prior no-action responses apply to the specific proposal and company at issue. Based on these considerations, we may determine that company X may exclude a proposal but company Y cannot exclude a proposal that addresses the same or similar subject matter. The following chart illustrates this point by showing that variations in the language of a proposal, or different bases cited by a company, may result in different responses.

Staff Legal Bulletin No. 14 (July 13, 2001). Xcel Energy believes that the Proposal, as applied to its nuclear plants in Minnesota, does not rise to the level of "significant social policy issue" for at least four reasons: (1) Xcel Energy's continual review and monitoring of plant safety and its maintenance of an effective program for implementing and inspecting its safety features is an ordinary feature of its business; (2) the enormously detailed policies and procedures based on complex scientific and engineering principles associated with nuclear regulation are not a proper subject for shareholder oversight and have over time become a part of Xcel Energy's ordinary business operations; (3) the nuclear plants at issue here are already operating plants, and the issue is not the construction or the conversion of a nuclear power plant, but rather relates to how these plants operate; and (4) Xcel

Energy's two nuclear plants—Monticello and Prairie Island—are both located in Minnesota in areas that the U.S. Geological Survey has indicated have the lowest seismic hazard risk, the topic the Proposal is largely centered around.

First, independent assessment and critique of our operations has always played an important role in ensuring that we are operating our nuclear plants safely in the interest of the communities surrounding our plants, our employees, our customers, and our shareholders going back to the Safety Audit Committees that were formed in the 1970s to independently advise the Chief Nuclear Officer regarding safety, plant operations, and regulatory matters. This focus on safety has resulted in Xcel Energy being a leader in responding to many of the safety issues that were identified and resolved in the 1980s. Xcel Energy was a leader in resolving structural and severe accident issues for the Mark I containments, implementing fire protection regulations following the Browns Ferry fire, enhancing designs for the control rod systems following the partial control rod insertion at the Salem nuclear plant, and identifying aging management programs to allow the long-term safe operation of nuclear power plants.

To further ensure the long-term safe operation of Xcel Energy's nuclear plants, Xcel Energy is subject to and meticulously follows the NRC's rigorous nuclear reactor regulations. Broken into seven cornerstones of safety, the NRC's reactor oversight process addresses (1) the initiating events that could disrupt plant operations, (2) the mitigating systems to alleviate the effects of initiating events, (3) the integrity of the three barriers between the highly radioactive fuel and the public and environment, (4) the plant's comprehensive emergency plans, (5) the levels of radiation doses received by plant workers, (6) the regulations designed to protect the public health from exposure to radioactive materials, and (7) the well-trained security personnel and protective systems to guard vital plant equipment. Moreover, the Staff has agreed in the past that matters regarding compliance with government regulations affecting, in part, nuclear plants involve ordinary business operations. That case, *Duke Power Company* (March 7, 1988), involved a proposal that sought a report on environmental protection and pollution control activities at, among others, nuclear power plants. The company argued that as a result of its many years of heavy regulation "by federal, state and local regulations in the environmental and safety areas," its compliance in those areas became "a significant part of the company's ordinary business operations [as] a utility." The Commission agreed, stating that the proposal "appears to deal with a matter relating to the conduct of the Company's ordinary business operations (i.e., compliance with governmental regulations relating to the environmental impact of power plant emissions)." Accordingly, Xcel Energy's many years of heavy regulation has rendered its compliance a part of its ordinary business operations, and as such a matter not for shareholder oversight. All of the foregoing—the continual review and monitoring of plant safety, the maintenance of an effective program for implementing and inspecting safety features, and the extensive regulations Xcel Energy subject to and complies with—are all serious but ultimately ordinary feature of our business.

Second, overseeing the safety and proper operation of Xcel Energy's power plants involves extremely detailed policies and procedures based on complex scientific and engineering principles. The development, operation, and containment of nuclear power facilities require significant technical expertise. Accordingly, it is not practical to expect shareholders as a body to oversee nuclear safety to the extent requested by the Proposal. The Proposal simply "prob[es] too deeply into matters of a complex nature." *Release No. 34-40018*. The Staff has permitted exclusion of proposals that seek to involve shareholders in highly technical matters. *See, e.g.*, *Carolina Power & Light Co.*

(March 8, 1990) (concurring with the exclusion of a shareholder proposal that requested a detailed report on the company's nuclear plant operations, including causes, consequences, and resolution of plant shut downs).

Third, *Release No. 34-12999*, which clarified the term "ordinary business operations," focuses exclusively on the construction of nuclear power plants as indicative of being a "significant social policy issue." As stated above, the nuclear plants at issue here are already operating plants, and as such the Proposal stands outside the Commission's guidance in *Release No. 34-12999*. Although the Staff suggested in *Florida Progress Corp.* that a proposal that concerns the operation of an existing nuclear plant may fall outside Rule 14a-8(i)(7), the proposal there is sufficiently different from the Proposal here to justify distinguishing the two. Whereas the proposal in *Florida Progress Corp.* focused on specific issues that directly affected the company's nuclear operations—i.e., number of deaths, modifications ordered by the NRC, "whistleblower" complaints, and the like—the Proposal here is drafted to focus largely on earthquake and seismic matters that only tangentially, if at all, affect the Monticello and Prairie Island nuclear plants (as discussed in more detail below). Additionally, the statement in the Proposal's resolution that the special review should be completed "in light of the extraordinary developments and findings described above" limits the reach of the Proposal to what is in the supporting statement (i.e., a discussion largely based on the risks associated with earthquakes, seismic events, etc.). Thus, as the Proposal is not within the arena of *Release No. 34-12999* and is distinguishable from *Florida Progress Corp.*, Xcel Energy believes it may exclude it pursuant to Rule 14a-8(i)(7).

Fourth, the Proposal requests "that a committee of Independent directors be appointed to conduct a special review of the company's nuclear safety policies and practices *in light of the extraordinary developments and findings described above*" (emphasis added), of which a substantial portion concerns earthquakes and seismic activity, and states that the special review should include "potential risks associated with seismic events in and around the company's nuclear power plants." Thus, it is evident that a major concern of the Proposal is nuclear safety in relation to earthquakes and related seismic activity. However, Xcel Energy's two nuclear plants are located in Minnesota, a state that has not in recorded history been subject to as severe of earthquakes as those referenced in the Proposal. Whereas the Proposal notes the Fukushima nuclear crisis in Japan, the result of an 8.9 magnitude on the richter scale earthquake, a 7.1 magnitude aftershock, and ensuing tsunami, and the loss of grid power at the North Anna Power Station in Virginia, the result of a 5.8 magnitude on the richter scale earthquake, the state of Minnesota, and thus Xcel Energy's nuclear plants, has not experienced in recorded history earthquake magnitudes anywhere near that seen in Fukushima or even Virginia. The locations of the Monticello and Prairie Island plants in Minnesota continue to show in the U.S. Geological Survey maps that they are in the lowest seismic hazard category of zero to four percent g (g is the acceleration of a falling object due to gravity). The relevant map is attached hereto as Exhibit G-1. To put this in perspective, Monticello and Prairie Island were designed to withstand 12 percent g. According to a report by the United States Geological Survey, which is attached hereto as Exhibit G-2, the largest earthquake ever to recorded in Minnesota occurred on July 9, 1975. The magnitude of that earthquake only reached 4.6 on the richter scale, and resulted in only minor damage to walls and foundations of basements in one county, Stevens. The last strongly felt earthquake in Minnesota occurred on September 3, 1917, near the City of Staples, and had a maximum intensity that was not greater than that of the 1975 earthquake. The particular facts here make clear that Xcel Energy's nuclear plants in Minnesota are not subject to the same risk of earthquakes and seismic activity as the reactor in Fukushima, Japan or even Virginia to which the Proponent refers. Therefore, drawing on the Commission's guidance in *Staff Legal Bulletin No. 14*, an analysis of the safety policies and practices in light of such developments and findings, "including seismic events in and around the company's nuclear power plants," does not rise to the level of "significant social policy issue." Rather, such an analysis remains within the ordinary course of business operations as applied to Xcel Energy, and is thus excludable under Rule 14a-8(i)(7).

Based on the foregoing, Xcel Energy may exclude the Proposal pursuant to Rule 14a-8(i)(7), as it deals with the company's "ordinary business operations."

C. The Proposal May Be Excluded Pursuant to Rule 14a-8(i)(3) Because It is Materially False and Misleading in Violation of Rule 14a-9.

Under Rule 14a-8(i)(3), a company may exclude a shareholder proposal from its proxy materials if the proposal or its supporting statement is contrary to the Commission's proxy rules, including Rule 14a-9, which prohibits materially false or misleading statements in proxy soliciting materials. False and misleading statements are not specifically defined in Rule 14a-8(i)(3) or Rule 14a-9, but are described as statements which are false and misleading as to any material fact or which omit to state any material fact necessary to make a statement not false or misleading or to correct an earlier statement. Therefore, Xcel Energy believes that Rule 14a-9 covers statements that impliedly represent a fact that is false. Where the company is able to objectively demonstrate this material falsity, exclusion under Rule 14a-8(i)(3) may be appropriate. *Staff Legal Bulletin No. 14B* (September 15, 2004).

The Proposal contains materially false and misleading statements regarding the risks associated with Xcel Energy's nuclear power plants. The Proposal's emphasis on the risks associated with seismic events and its mandate "to conduct a special review . . . including potential risks associated with seismic events in and around the company's nuclear power plants" suggests that Xcel Energy has power plants that are at risk of seismic events sufficient to cause damage to its nuclear reactors. Xcel Energy's nuclear plants—Monticello and Prairie Island—are both located in Minnesota. The Proposal references the 8.9 on the richter scale magnitude earthquake and 7.1 magnitude aftershock in Fukushima, Japan and the 5.8 on the richter scale magnitude earthquake in Virginia. As discussed above, Minnesota has not in recorded history experienced earthquake magnitudes anywhere near that seen in Fukushima or even Virginia. In addition, Xcel Energy's plants are located in areas with the lowest seismic hazard category of zero to four percent g. Accordingly, to frame a significant portion of the Proposal in that light suggests that Xcel Energy's nuclear plants, like those in Fukushima, Japan and Virginia, are subject to earthquakes and related seismic events sufficient to result in the same degree of safety issues, when in reality they are not. U.S. nuclear reactors are not similarly impacted by exposure to seismic risks, and owners of plants such as Palo Verde or others in high seismic risk areas are responding in a significantly different manner to the events that occurred in Fukushima, Japan than Xcel Energy is with respect to its plants.

The Staff consistently has allowed the exclusion under Rule 14a-8(i)(3) of shareholder proposals that contain false or misleading implications. For instance, in *Wal-Mart Stores, Inc.* (April 2, 2001), the Staff permitted the exclusion of a shareholder proposal that sought the adoption of a policy to "phase out genetically engineered crops, organisms, or products thereof from all products sold or manufactured by the company." The Staff granted no-action relief, in part, on the basis that the proposal was misleading because it *implied* that it would only affect the sale of food products, while in reality it would apply to any genetically engineered crop or organism, including chewing gum, glues and pastes, toothpaste, shoe polish, and the like. *See also Exelon Corp.* (December 18, 2009) (concurring with the exclusion of a shareholder proposal that included quotation marks around the word "donated," and thereby implied that the company either gave money to another entity as a favor to a particular Senator or as a charitable donation, and, in effect, that the company had been involved in corrupt practices). Similar to the *Wal-Mart Stores, Inc.* and *Exelon Corp.* no-action letters, the Proposal at issue here falsely implies that Xcel Energy's nuclear plants are subject to the same or even similar seismic events seen by Fukushima, Japan or the state of Virginia. Based on the foregoing data provided by the United States Geological Survey, it is evident that such an implication is incorrect, and thus objectively misleading. Therefore, the Proposal may be properly excluded pursuant to Rule 14a-8(i)(3) as it is in violation of Rule 14a-9's prohibition against materially false and misleading proxy solicitations.

Conclusion

Based upon the foregoing analysis, we respectfully request that the Staff confirm that it will not recommend any enforcement action to the Commission if Xcel Energy excludes the Proposal from its 2012 Proxy Materials pursuant to Rule 14a-8. We would be happy to provide any additional information and answer any questions regarding this matter. Should you disagree with the conclusions set forth in this letter, we would appreciate the opportunity to confer prior to the determination of the Staff's final position.

Please do not hesitate to call me at (612) 330-5500 if I can be of any further assistance in this matter.

Thank you for your consideration.

Best Regards,

Scott Wilensky

Scott Wilensky
Senior Vice President and General
Counsel
Xcel Energy Inc.

cc: Patrick Doherty
Director, Corporate Governance
Pension Investments & Cash Management
State of New York Office of the State Comptroller
633 Third Avenue, 31st Floor
New York, New York 10017

Exhibit A

THOMAS P. DINAPOLI
STATE COMPTROLLER

STATE OF NEW YORK
OFFICE OF THE STATE COMPTROLLER

PENSION INVESTMENTS
& CASH MANAGEMENT
633 Third Avenue-31st Floor
New York, NY 10017
Tel: (212) 681-4489
Fax: (212) 681-4468

December 6, 2011

Cathy James Hart
Corporate Secretary
Xcel Energy Inc.
414 Nicollet Mall, Suite 500
Minneapolis, Minnesota 55401-1993

Dear Ms. Hart:

The Comptroller of the State of New York, The Honorable Thomas P. DiNapoli, is the sole Trustee of the New York State Common Retirement Fund (the "Fund") and the administrative head of the New York State and Local Employees' Retirement System and the New York State Police and Fire Retirement System. The Comptroller has authorized me to inform Xcel Energy, Inc. of his intention to offer the enclosed shareholder proposal on behalf of the Fund for consideration of stockholders at the next annual meeting.

I submit the enclosed proposal to you in accordance with rule 14a-8 of the Securities Exchange Act of 1934 and ask that it be included in your proxy statement.

A letter from J.P. Morgan Chase, the Fund's custodial bank, verifying the Fund's ownership, continually for over a year, of Xcel Energy, Inc. shares, will follow. The Fund intends to continue to hold at least $2,000 worth of these securities through the date of the annual meeting.

We would be happy to discuss this initiative with you. Should the board decide to endorse its provisions as company policy, we will ask that the proposal be withdrawn from consideration at the annual meeting. Please feel free to contact me at (212) 681-4823 should you have any further questions on this matter.

Very truly yours,

Patrick Doherty
pd:jm
Enclosures

SPECIAL BOARD REVIEW OF NUCLEAR POWER SAFETY ISSUES

WHEREAS, the Fukushima nuclear crisis in Japan, brought on by an earthquake and tsunami, and the August, 2011 earthquake on the US east coast, have drawn increased attention to issues related to nuclear power safety, and

WHEREAS, Xcel Energy currently owns and operates two nuclear power plants in the state of Minnesota, and

WHEREAS, independent studies have indicated that nuclear power plants continue to experience problems with safety-related equipment and worker errors that increase the risk of damage to the reactor cores, and that recognized but misdiagnosed or unresolved problems often cause significant events at nuclear plants, or increase their severity, and

WHEREAS, a March, 2011 report by the Union of Concerned Scientists analyzed a series of U.S. reactor incidents in 2010 that prompted special intervention by the Nuclear Regulatory Commission("NRC"). The report found that these events were caused by a variety of shortcomings such as "inadequate training, faulty maintenance, poor design, and failure to investigate problems thoroughly (Union of Concerned Scientists, The NRC and Nuclear Power Plant Safety in 2010: A Brighter Spotlight Needed (2011)), http://www.ucsusa.org/assets/documents/nuclear_power/nrc-2010-full-report.pdf, and

WHEREAS, this report recommends that companies operating nuclear plants adopt enhanced safety measures, including transferring spent nuclear fuel from storage pools to dry casks once it has cooled, and that companies comply fully with fire protection regulations issued by the NRC in 1980 and 2004 -- recommendations which could help to reduce the plants' vulnerabilities in the event of an earthquake or other significant event, and

WHEREAS, following the August, 2011 earthquake on the U.S. east coast, the Wall Street Journal reported that U.S. regulators have concluded that "more seismic activity is now considered possible in the U.S. than had been understood when older plants were built", ("Nuclear Site Status Checked" Wall Street Journal 8 Aug. 2011), and that a number of U.S. plants were now threatened by tremors greater than they were designed to withstand. (Dominion Resource's North Anna Power Station in Virginia, located 10 miles from the epicenter of the August 23,2011 5.8 magnitude earthquake, lost normal grid power and was shut down for several months),

THEREFORE, be it resolved that shareholders request that a committee of independent directors be appointed to conduct a special review of the company's nuclear safety policies and practices in light of the extraordinary developments and findings described above, including potential risks associated with seismic events in and around the company's nuclear power plants, and that that committee report to shareholders on its findings at reasonable expense and excluding proprietary or confidential information.

Exhibit B

XCEL ENERGY INC.
Nuclear, Environmental, and Safety Committee Charter
(Last Amended February 17, 2010)
(Reviewed and adopted without amendment on June 22, 2011)

A. **Authority.** The Nuclear, Environmental, and Safety Committee is granted the authority by the Board of Directors to perform each of the specific duties set forth in this Committee Charter. The Nuclear, Environmental, and Safety Committee will be provided adequate resources to discharge its responsibilities and will receive staff support from Xcel Energy's business unit leaders with responsibility for the Company's operating functions.

B. **Responsibilities.** The Nuclear, Environmental, and Safety Committee shall assist the Board of Directors in oversight of the nuclear strategy and nuclear operations of the Company and its subsidiaries; environmental strategy and compliance; and safety performance. In performing this function, the Committee members will provide advice to the Chief Executive Officer and senior executives and will review appropriate issues such as nuclear plant performance, safety and compliance; safety aspects of operations; and environmental strategy, compliance, and performance.

C. **Membership and Qualification:** The size of the Committee shall be determined by the Board, but it must always have at least three members.

Desirable qualifications for Committee members include experience in business, utility operations, nuclear operations, environmental issues, industrial safety and other related areas.

The Board selects Committee members based on identified needs and recommendations of the Committee. Each Committee member will serve at the pleasure of the Board for such term as the Board may decide or until such Committee member is no longer a Board member.

D. **Specifications.** The Nuclear, Environmental, and Safety Committee shall:

1. Provide oversight of the Company's nuclear strategy and operations, including a review of the results of major inspections and evaluations by external oversight and regulatory bodies, and reports of the independent Nuclear Oversight Committee. Members will review the state of the nuclear industry.

2. Review the Company's safety performance and safety strategy and initiatives.

3. Review the Company's environmental strategy, compliance, performance issues and initiatives.

4. Review of material risks relating to our nuclear operations and our environmental and safety performance, including risks to the Company's reputation.

5. Conduct an annual assessment of the performance of the Committee in the fulfillment of its functions and the performance of its responsibilities.

E. **Meetings.** The Nuclear, Environmental, and Safety Committee shall meet three times during the calendar year and at such other times as may be requested by its Chairman or a majority of its members.

F. **Meeting Attendance.** A majority of the members of the Nuclear, Environmental, and Safety Committee shall constitute a quorum for the transaction of business at any meeting of the Committee. The executive officer as designated by the Chairman and CEO, in conjunction with the executive officers responsible for Nuclear, Environment, and Safety functions in the Company, shall be the coordinating officer for the Committee and attend all meetings as appropriate. Other management representatives shall attend as necessary.

G. **Supporting Material and Agendas.** The Committee Chairman, in consultation with the Committee Coordinating Officer and the appropriate executive officers, shall prepare the meeting agenda for approval by the Committee Chairman. The agenda and all materials to be reviewed at a Committee meeting shall be provided to the Committee members at least five days prior to the meeting date.

Signed:

______________________________ Date: June 21, 2011

Chairman of the,
Nuclear, Environmental, and Safety Committee

______________________________ Date: June 22, 2011

Chairman of the Board

Exhibit C-1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, IL 60532-4352

May 13, 2011

Mr. Timothy J. O'Connor
Site Vice President
Monticello Nuclear Generating Plant
Northern States Power Company, Minnesota
2807 West County Road 75
Monticello, MN 55362-9637

SUBJECT: MONTICELLO NUCLEAR GENERATING PLANT – NRC TEMPORARY INSTRUCTION 2515/183 INSPECTION REPORT 05000263/2011009

Dear Mr. O'Connor:

On April 29, 2011, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Monticello Nuclear Generating Plant, using Temporary Instruction 2515/183, "Followup to the Fukushima Daiichi Nuclear Station Fuel Damage Event." The enclosed inspection report documents the inspection results which were discussed on April 26, 2011, with Mr. John Grubb and other members of your staff.

The objective of this inspection was to promptly assess the capabilities of Monticello Nuclear Generating Plant to respond to extraordinary consequences similar to those that have recently occurred at the Japanese Fukushima Daiichi Nuclear Station. The results from this inspection, along with the results from this inspection performed at other operating commercial nuclear plants in the United States, will be used to evaluate the U.S. nuclear industry's readiness to safely respond to similar events. These results will also help the NRC to determine if additional regulatory actions are warranted.

All of the potential issues and observations identified by this inspection are contained in this report. The NRC's Reactor Oversight Process will further evaluate any issues to determine if they are regulatory findings or violations. Any resulting findings or violations will be documented by the NRC in the next quarterly report. You are not required to respond to this letter.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Kenneth Riemer, Chief
Branch 2
Division of Reactor Projects

Docket No. 50-263
License No. DPR-22

Enclosure: Inspection Report 05000263/2011009

cc w/encl: Distribution via ListServe

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-263
License No:	DRP-22
Report No:	05000263/2011009
Licensee:	Northern States Power Company, Minnesota
Facility:	Monticello Nuclear Generating Plant
Location:	Monticello, Minnesota
Dates:	March 23 through April 29, 2011
Inspector:	S. Thomas, Senior Resident Inspector
Approved by:	Kenneth Riemer Branch 2 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000263/2011009, 03/23/2011 – 04/29/2011; Monticello Nuclear Generating Plant Temporary Instruction 2515/183 - Followup to the Fukushima Daiichi Nuclear Station Fuel Damage Event.

This report covers an announced Temporary Instruction (TI) inspection. The inspection was conducted by Resident and Region III inspectors. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

INSPECTION SCOPE

The intent of the TI is to provide a broad overview of the industry's preparedness for events that may exceed the current design basis for a plant. The focus of the TI was on (1) assessing the licensee's capability to mitigate consequences from large fires or explosions on site, (2) assessing the licensee's capability to mitigate station blackout (SBO) conditions, (3) assessing the licensee's capability to mitigate internal and external flooding events accounted for by the station's design, and (4) assessing the thoroughness of the licensee's walk downs and inspections of important equipment needed to mitigate fire and flood events to identify the potential that the equipment's function could be lost during seismic events possible for the site. If necessary, a more specific follow-up inspection will be performed at a later date.

INSPECTION RESULTS

All of the potential issues and observations identified by this inspection are contained in this report. The NRC's Reactor Oversight Process will further evaluate any issues to determine if they are regulatory findings or violations. Any resulting findings or violations will be documented by the NRC in the next quarterly report.

03.01 Assess the licensee's capability to mitigate conditions that result from beyond design basis events, typically bounded by security threats, committed to as part of NRC Security Order Section B.5.b issued February 25, 2002, and severe accident management guidelines as required by Title 10 of the Code of Federal Regulations (10 CFR) 50.54 (hh). Use Inspection Procedure (IP) 71111.05T, "Fire Protection (Triennial)," Section 02.03 and 03.03 as a guideline. If IP 71111.05T was recently performed at the facility, the inspector should review the inspection results and findings to identify any other potential areas of inspection. Particular emphasis should be placed on strategies related to the spent fuel pool. The inspection should include, but not be limited to, an assessment of any licensee actions to:

Licensee Action	Describe what the licensee did to test or inspect equipment.
a. Verify through test or inspection that equipment is available and functional. Active equipment shall be tested and passive equipment shall be walked down and inspected. It is not expected that permanently installed equipment that is tested under an existing regulatory testing program be retested. This review should be done for a reasonable sample of mitigating strategies/equipment.	The licensee performed walkdowns with qualified operators and discussions took place regarding the use of the procedures and the desired result, as well as the required equipment. Equipment inventories were completed using approved site procedures with all gaps noted in the corrective action process. Monticello has the capability to mitigate conditions that result from beyond basis events, typically bounded by security threats, committed to as part of B.5.b licensing process and using severe accident management guidelines. The flooding events require materials not currently onsite, but the procedure is written assuming the flooding can be predicted allowing for the material to be obtained and barriers constructed. The following procedures were performed to verify equipment was available and functional: • 1488; Emergency Operating Procedures (EOP)/Abnormal Operating Procedures (AOP) Equipment Inventory; • 1224; Fire Brigade Equipment Inventory; • OSP-FIR-0582; Portable Diesel Fire Pump Testing Procedure; • ESP-125-0583; 125V DC Portable Battery Cart Testing Procedure; and • IMP-1023; Fluke Model 87V EX Digital Multimeter Performance Test. Procedure 1224 requires that the operator perform a condition inspection using criteria outlined in the procedure. Active equipment, such as the portable diesel fire pump and 125 VDC battery cart, were tested using approved site procedures. The 1488 procedure does not specifically require that an inspection be performed during the equipment inventory. Nonetheless, the inventory done for this activity did assess the condition and readiness of the equipment. All Emergency Operating Procedure (EOP) equipment was validated to be stored in the proper location.

	Describe inspector actions taken to confirm equipment readiness (e.g., observed a test, reviewed test results, discussed actions, reviewed records, etc.).
	The inspectors assessed the licensee's capabilities by conducting a review of the licensee's walkdown activities. In addition, the inspectors independently walked down and inspected a sampling of the major B.5.b contingency equipment staged throughout the plant.
	Discuss general results including corrective actions by licensee.
	During the EOP inventory, equipment was found to be stored in areas that could potentially be susceptible to damage during a seismic event. While performing the fire brigade inventory (1224), some equipment was not in the proper storage location, and some equipment called out in the B.5.b procedures was not on the inventory as expected. Corrective actions were documented to correct these issues. The missing equipment from the B.5.b procedures is readily available at numerous locations onsite; however, a dedicated supply was not in the dedicated B.5.b storage location. Specific corrective action program (CAP) documents applicable to this section are listed in Section 3.01(e). No issues of significance were identified by the inspectors.

Licensee Action	Describe the licensee's actions to verify that procedures are in place and can be executed (e.g., walkdowns, demonstrations, tests, etc.).
b. Verify through walkdowns or demonstration that procedures to implement the strategies associated with B.5.b and 10 CFR 50.54 (hh) are in-place and are executable. Licensees may choose not to connect or operate permanently installed equipment during this verification. This review should be done for a reasonable sample of mitigating strategies/equipment.	The A.7 – Severe Accident Mitigation Guidelines (SAMG) procedures are in-place and executable. This was demonstrated by a tabletop exercise using an Accident Management Team (AMT) stationed in the Technical Support Center (TSC) with an operator in the control room simulator to demonstrate the communication link. The tabletop exercise challenged all legs of the SAMGs. Activities to be performed in the plant were done by operations personnel in a walk-through format with an evaluator observing their performance. The AMT was able to complete priority actions that would have ensured event mitigation. The SAMGs refer to multiple EOP Support Procedures (C.5-3XXX) that are part of the regular training cycle for the Operations crews. All actions performed by Operations during SAMG situations are in the EOP Support Procedures. Several of the A.8 (Extensive Damage Mitigation Strategy (EDMG) Overview) procedures that implement the B.5.b program requirements are in-place and validated as executable via walkdowns.

	Describe inspector actions and the sample strategies reviewed. Assess whether procedures were in place and could be used as intended.
	The inspectors assessed the licensee's capabilities by conducting a review of the licensee's walkdown activities. In addition, the inspectors selected several sections of a sample of the procedures walked down by the licensee and walked them down to independently verify the licensee's conclusions. The inspectors did not observe the performance of the tabletop exercise, but did review the exercise materials.
	Discuss general results including corrective actions by licensee.
	No gaps were identified that would impair the station's ability to utilize these mitigation strategies. Several enhancement opportunities were documented and entered in the licensee's corrective action process. Specific CAP documents applicable to this section are listed in Section 3.01(e). No issues of significance were identified by the inspectors.

Licensee Action	**Describe the licensee's actions and conclusions regarding training and qualifications of operators and support staff.**
c. Verify the training and qualifications of operators and the support staff needed to implement the procedures and work instructions are current for activities related to Security Order Section B.5.b and severe accident management guidelines as required by 10 CFR 50.54 (hh).	The licensee conducted a review of their Emergency Plan (EP) Training Program, as well as a qualification search for the number of individuals qualified in each position, via the Learning Management System (LMS) tool. The Training Department verified that all positions in the six ERO duty teams were staffed by individuals qualified in their associated jobs.
	Describe inspector actions and the sample strategies reviewed to assess training and qualifications of operators and support staff
	The inspectors assessed the licensee's training and qualification activities by conducting a review of training and qualification materials and records related to the current Emergency Response Organization (ERO) qualifications of the assigned site staff.

	Discuss general results including corrective actions by licensee.
	The training requirements, qualifications, and associated records needed to verify that the site's ERO could be staffed and function during an event, were reviewed by the licensee. This recommendation is being met in accordance with site procedures and regulatory commitments. No deficiencies were noted when applicable training and qualification documents were reviewed. Specific CAP documents applicable to this section are listed in Section 3.01(e). No issues of significance were identified by the inspectors.

Licensee Action	**Describe the licensee's actions and conclusions regarding applicable agreements and contracts are in place.**
d. Verify that any applicable agreements and contracts are in place and are capable of meeting the conditions needed to mitigate the consequences of these events. This review should be done for a reasonable sample of mitigating strategies/equipment.	The licensee performed a review of B.5.b and SAMG procedures to determine what equipment is required from offsite venders to successfully implement their procedures. The review was also expanded to include flooding and SBO concerns to consolidate the scope and content of the agreements/contracts. The licensee conducted interviews of site program owners to determine what contracts were in place and what services, equipment, or materials offsite entities had agreed to provide. **For a sample of mitigating strategies involving contracts or agreements with offsite entities, describe inspector actions to confirm agreements and contracts are in place and current (e.g., confirm that offsite fire assistance agreement is in place and current).** The inspectors assessed the licensee's capabilities by conducting an independent review of the licensee's letters of agreement, memorandums of understanding, and contracts for goods and services counted on to successfully implement their SAMGs and EDMGs. The inspectors verified that each was current and whether or not each was adequate for meeting the licensee's mitigation strategy.

		Discuss general results including corrective actions by licensee.
		Gaps were identified during the licensee's review of offsite equipment that might be necessary to effectively implement their mitigating strategies. Corrective action documents have been initiated for the site to determine what equipment should be available onsite and what agreements are adequate for equipment that comes from offsite sources. At this time, the site has not made formal agreements to provide all equipment required from offsite entities. The licensee has determined that the agreements that are currently in place are sufficient to provide resources that the site might request in the event to allow for effective utilization of their mitigation strategies. Further review is required to determine what equipment should be purchased for onsite storage and what formal agreements should be made with offsite suppliers. Specific CAP documents applicable to this section are listed in Section 3.01(e). No issues of significance were identified by the inspectors.

Licensee Action	Document the corrective action report number and briefly summarize problems noted by the licensee that have significant potential to prevent the success of any existing mitigating strategy.
e. Review any open corrective action documents to assess problems with mitigating strategy implementation identified by the licensee. Assess the impact of the problem on the mitigating capability and the remaining capability that is not impacted.	The following entries into the licensee's CAP were made to address issues identified during the evaluation of IER 11-1; Recommendation 1: • CAP 1276717; IER 11-1 – Emergency Planning Enhancements • CAP 1276710; IER 11-1 – SAMG/EOP Procedure Enhancements • CAP 1276567; IER 11-1 – SAMG/EDMG Training Improvements • CAP 1280884; IER 11-1 – Improve Training for SAMGs • CAP 1276416; IER 11-1 – During the 1224 Fire Equipment Inventory, Numerous Deficiencies were Found • CAP 1276377; Abnormal Charger Indication during ESP-125-0583 • CAP 1276324; IER 11-1 - Vulnerabilities (Several Seismic Type Vulnerabilities have been Identified) • CAP 1276101; O2 Storage Rack not Anchored to the Wall • CAP 1276098; IER 11-1 – Shelves in Alt Fire Brigade Room not Anchored to the Wall • CAP 1276096; IER 11-1 – RCIC Tachometer Found Out of Calibration • CAP 1276088; Materials Staged Limiting Access to EOP Equipment • CAP 1276087; IER 11-1 – Training Improvement on Use of SAMG/EDMG in Emergency Plan • CAP 1276692; Not All Equipment Called for Use in A.8 Procedures (EDMGs) was Listed on the Fire Brigade Inventory • CAP 1276414; N2 Tank Used to Support C.5-1301 (Alternate Rod Insertion) could be Damaged in a Seismic Event • CAP 1278817; EOP Equipment Inventory does not Require Inspection of the Equipment • CAP 1276707; Offsite Support Equipment for A.8 not Assured Available • CAP 1276715; Offsite Support Equipment for A.6 Procedure Not Assured Available • CAP 1280539; Equipment Needed to Perform EDMGs not in Specified Location • CAP 1280633; IER 11-1 – Can B.5.b/SAMG Equipment do Simultaneous Tasks? The inspectors reviewed each condition report for potential impact to the licensee's mitigation strategies. No significant impacts were identified.

03.02 Assess the licensee's capability to mitigate station blackout (SBO) conditions, as required by 10 CFR 50.63, "Loss of All Alternating Current Power," and station design is functional and valid. Refer to TI 2515/120, "Inspection of Implementation of Station Blackout Rule Multi-Plant Action Item A-22," as a guideline. It is not intended that TI 2515/120 be completely reinspected. The inspection should include, but not be limited to, an assessment of any licensee actions to:

Licensee Action	**Describe the licensee's actions to verify the adequacy of equipment needed to mitigate an SBO event.**
a. Verify through walkdowns and inspection that all required materials are adequate and properly staged, tested, and maintained.	Abnormal Operating Procedure C.4-B.09.02A (Station Blackout) is the governing procedure for the plant response to a SBO. This procedure implements the few specific requirements for mitigating the design basis SBO. This procedure also has steps which are not required for design basis mitigation, but serve to increase the coping duration beyond the required four hour period. The MNGP staff performed C.4-B.09.02A using the control room simulator combined with a plant walkdown to assure that all required materials and procedures are adequate, properly staged, and executable to support the design basis SBO mitigation.
	Describe inspector actions to verify equipment is available and useable.
	The inspectors assessed the licensee's capability to mitigate SBO conditions by conducting a review of the licensee's walkdown activities. In addition, the inspectors selected a sample of equipment utilized/required for mitigation of a SBO and conducted independent walkdowns of that equipment to verify that the equipment was properly aligned and staged.
	Discuss general results including corrective actions by licensee.
	Operators verified that the steps in this procedure that are required to meet the four hour coping duration are executable. No issues of significance were identified by the inspectors.

Licensee Action	Describe the licensee's actions to verify the capability to mitigate an SBO event.
b. Demonstrate through walkdowns that procedures for response to an SBO are executable.	Abnormal Operating Procedure C.4-B.09.02A (Station Blackout) is the governing procedure for the plant response to a SBO. This procedure implements the few specific requirements for mitigating the design basis SBO. This procedure also has steps which are not required for design basis mitigation, but serve to increase the coping duration beyond the required four hour period. The MNGP staff performed C.4-B.09.02A using the control room simulator combined with a plant walkdown to assure that all required materials and procedures are adequate, properly staged, and executable to support the design basis SBO mitigation.
	Describe inspector actions to assess whether procedures were in place and could be used as intended.
	The inspectors assessed the licensee's capabilities by conducting a review of the licensee's walkdown activities. In addition, the inspectors selected several sections of a sample of the procedures walked down by the licensee and walked those down to independently verify the licensee's conclusions.
	Discuss general results including corrective actions by licensee.
	Operation staff verified that the steps in this procedure that are required to meet the four hour coping duration are executable. Items that were identified by the licensee and entered into their CAP to address issues identified during the evaluation of IER 11-1, Recommendation 2, are listed in the List of Documents Reviewed at the end of this report. No issues of significance were identified by the inspectors.

03.03 Assess the licensee's capability to mitigate internal and external flooding events required by station design. Refer to IP 71111.01, "Adverse Weather Protection," Section 02.04, "Evaluate Readiness to Cope with External Flooding," as a guideline. The inspection should include, but not be limited to, an assessment of any licensee actions to verify through walkdowns and inspections that all required materials and equipment are adequate and properly staged. These walkdowns and inspections shall include verification that accessible doors, barriers, and penetration seals are functional.

Licensee Action	Describe the licensee's actions to verify the capability to mitigate existing design basis flooding events.
a. Verify through walkdowns and inspection that all required materials are adequate and properly staged, tested, and maintained.	The structures, systems, and components (SSCs) credited in MNGP's External Flooding, Internal Flooding, and High Energy Line Break (HELB) programs were cataloged. This catalogue list included all SSCs which control the movement of water between adjacent volumes and the boundary penetrations between these adjacent volumes. Only the penetrations at or below maximum probable water levels based on station flooding calculations were evaluated. Utilizing this list, field walkdowns were conducted to assess the condition of the flood control SSCs. For external flooding, a walkdown was performed to ensure pathways were clear and capable of performing their function (i.e., passage of water along the path assumed in the applicable calculation). The acceptability of the flood barriers and relief paths was documented on the list of the flood control SSCs.
	Describe inspector actions to verify equipment is available and useable. Assess whether procedures were in place and could be used as intended.
	The inspectors assessed the licensee's capabilities to mitigate flooding by conducting a review of the licensee's walkdown activities. Flood mitigation procedures were reviewed to verify usability. In addition, the inspectors conducted independent walkdowns of selected flood mitigation equipment to independently assess the licensee's flood mitigation capabilities.

		Discuss general results including corrective actions by licensee.
		Of the 377 components to be inspected, 39 were not accessible. Monticello Nuclear Generating Plant is currently in a Refueling Outage (RFO). Currently during the refueling outage, work at the plant has required partial disassembly of credited barriers, created temporary openings through boundaries, restricted access to protected equipment, and obstructed viewing of some equipment by scaffold or other non-permanent tools and equipment staged for work. These items will be tracked as follow-on actions, with walkdowns to be conducted when station conditions permit. A walkdown was performed of the accessible plant areas having flood barriers and required relief paths. Walkdown notes documented the acceptability of every SSC and the cases where SSCs were inaccessible and could not be inspected. Items that were identified by the licensee and entered into their CAP to address issues identified during the evaluation of IER 11-1, Recommendation 3, are listed in the List of Documents Reviewed at the end of this report. No issues of significance were identified by the inspectors.

03.04 Assess the thoroughness of the licensee's walkdowns and inspections of important equipment needed to mitigate fire and flood events to identify the potential that the equipment's function could be lost during seismic events possible for the site. Assess the licensee's development of any new mitigating strategies for identified vulnerabilities (e.g., entered it in to the corrective action program and any immediate actions taken). As a minimum, the licensee should have performed walkdowns and inspections of important equipment (permanent and temporary), such as storage tanks, plant water intake structures, and fire and flood response equipment, and developed mitigating strategies to cope with the loss of that important function. Use IP 71111.21, "Component Design Basis Inspection," Appendix 3, "Component Walkdown Considerations," as a guideline to assess the thoroughness of the licensee's walkdowns and inspections.	
Licensee Action	**Describe the licensee's actions to assess the potential impact of seismic events on the availability of equipment used in fire and flooding mitigation strategies.**
a. Verify through walkdowns that all required materials are adequate and properly staged, tested, and maintained.	Important SSCs for fire protection were determined as equipment that can mitigate post safe-shutdown earthquake (SSE) fires in the following four categories: • permanently installed fire protection systems; • permanently installed, seismically-qualified non-fire protection systems that could be used to fight fires; • portable equipment that could be used to fight fires after an SSE; and • offsite responders. These categories of equipment, individually or in aggregate, must be capable of fighting fires in the critical portions of the station. Examples of critical portions of the station could include: • control room and support structures; • electrical switchgear rooms; • turbine building; • reactor building; • diesel generator buildings; • main and auxiliary transformers; and • intake structures. Piping and instrumentation diagrams were used to define the boundaries of the fire protection system within the scope of this recommendation, and the flood protection SSCs for this recommendation are the same as those used for Recommendation 3.

	The licensee enlisted a contractor, who specializes in the evaluation of the impacts of seismic activity on structures, to perform walkdowns of specific areas onsite. Working from the lists of fire protection and flood protection SSCs provided by the licensee, this contractor performed a walkdown and examined all of the flood and fire mitigation SSCs which were identified, and assessed the seismic vulnerability of these SSCs as high, medium, or low. A low vulnerability meant that the SSC would clearly withstand the SSE for the Monticello site. A medium vulnerability meant it was highly likely that the component would be shown through analysis to be able to survive the SSE for Monticello. A high vulnerability meant that it was quite possible that an SSE would disable the component.
	Describe inspector actions to verify equipment is available and useable. Assess whether procedures were in place and could be used as intended.
	The inspectors conducted multiple walkdowns of important equipment needed to mitigate fire and flood events to identify the potential that the equipment's function could be lost during or subsequent to a seismic event. Specific equipment reviewed as part of this assessment included a sampling of the major B.5.b contingency response equipment, installed fire protection and suppression equipment, installed diesel and electric fire pumps, and watertight hatches and floor plugs. In addition to the walkdowns, the inspectors reviewed a report prepared by the contractor which documented the results of how site flood and fire mitigation equipment would be impacted by an SSE.
	Discuss general results including corrective actions by licensee. Briefly summarize any new mitigating strategies identified by the licensee as a result of their reviews.
	For fire protection, the overall conclusion was that the system would likely suffer key failures in an SSE and could not be relied upon to be available after an earthquake. The mitigation strategy is to use B.5.b equipment to fight any fires that would occur following an earthquake. The B.5.b equipment is stored in a warehouse that is not designed as a Seismic Class I structure, but was examined by seismic experts and was it was concluded that it would remain intact following an SSE. Items that were identified by the licensee and entered into their CAP to address issues identified during the evaluation of IER 11-1, Recommendation 4, are listed in the List of Documents Reviewed at the end of this report. No issues of significance were identified by the inspectors.

Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. Grubb, and other members of licensee management, at the conclusion of the inspection on April 26, 2011. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

T. O'Connor, Site Vice President
J. Grubb, Plant Manager
W. Paulhardt, Assistant Plant Manager
N. Haskell, Site Engineering Director
K. Jepson, Business Support Manager
S. Radebaugh, Maintenance Manager
M. Holmes, Radiation Protection/Chemistry Manager
S. Leonard, Regulatory Affairs Manager
J. Earl, Emergency Preparedness Manager

Nuclear Regulatory Commission

K. Riemer, Chief, Reactor Projects Branch 2

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

03.01 Assess the licensee's capability to mitigate conditions that result from beyond design basis events

Number	Description or Title	Date or Revision
1488	Cycle Inventory of Equipment for EOP C.5-3XXX and AOP C.4 Series Procedures	Revision 1*
1244	Fire Brigade Equipment Inventory	Revision 27
OSP-FIR-0582	Portable Diesel Fire Pump Testing Procedure	Revision 2
ESP-125-0583	125V DC Portable Battery Cart Testing Procedure	Revision 2
IMP-1023	Fluke Model 87V EX Digital Multimeter Performance Test	Revision 3
A.8 Procedure Series	Extensive Damage Mitigation Strategies (various)	
A.7-SAMG-01	Primary Containment Flooding	Revision 5
A.7-SAMG-02	RPV, Containment, and Radioactivity Release Control	Revision 3
A.7-SAMG-03	Combustible Gas Control	Revision 1
	XE Nuclear LMS Qualification Status Verification for Turbine Building Operator; Reactor Building Operator; Reactor Operator; Senior Reactor Operator; Operations Shift Manager; Emergency Director; Support Group Leader; Security Group Leader/Emergency Operation Facility (EOF) Security Coordinator; Engineering Group Leader; Engineering Group; Core Thermal Hydraulics; Nuclear Engineer; Maintenance Group Leader; SM/CRS/Operations Group Leader; Radiological Emergency Coordinator; Monitoring Section Leader; Shift Emergency Communicator; Midas Dose Projection; Emergency Manager/Recovery Manager; Radiation Protection Support Supervisor; EOF Coordinator; Technical Support Supervisor; Field Team Coordinator; OSC Coordinator; Chemists; Electrical; I&C; Mechanical; SAMG Decision Makers; and SAMG Evaluators.	04/03/2011

03.02 Assess the licensee's capability to mitigate station blackout (SBO) conditions

Number	Description or Title	Date or Revision
C.4-B.0902.A	Station Blackout	Revision 36
C.4-B.0902.B	Loss of Normal Offsite Power	Revision 12
E.4-01	Backfeed Bus 13 from 13 DG	Revision 3
8153	Powering Division II 250 VDC Battery Chargers from No. 13 Diesel, Security Diesel or Portable Generator	Revision 3
CAP 1276138-01	Initiate PCR for 8153 Procedure Enhancements	

CAP 1276138-03	Verify Incorporation of the CAPX 2020 Subyard Modifications into E.5 Procedure	
CAP 1276138-04	Enhancement to Attach Relay Boots to the C.4 Station Blackout Procedure	
CAP 1279730	Actions to Enhance Extended SBO Coping Abilities	
8900	Operation of RCIC without Electric Power	Revision 2
E.5	System Electrical Blackout	Revision 12
CA-05-136	SBO Coping	Revision 15

03.03 Assess the licensee's capability to mitigate internal and external flooding events required by station design

Number	Description or Title	Date or Revision
A.6	Acts of Nature	Revision 37
CA-07-021	Internal Flooding – Reactor Building, Turbine Building and Intake Structure Water Height	Revision 0
CA-07-029	RX and Turbine Building and Intake Structure Water Height for Internal Flooding	Revision 0
Form 3336	HELB Barrier Start-Up Checklist	Revision 24
CAP 1277413	Strategies for External Flood might be Inadequate	
CAP 1276767	A.6; Rev 37 – TSC not Included in Earth Ring Levee	
CAP 1277785	A.6; Ext Flooding Procedure Lacks In-Place Barrier Walkdowns	
CAP 1276143	IER 1-11-1; Flood Plan does not ID Impact on Radioactive Material	
CAP 1279439	Security Training Facilities not Included in Trigger Actions of A.6	
CAP 1279440	New Security Building not Inside Earth Ring Levee	
CAP 1279342	Four SSCs not Modeled in Flood Analysis	
CAP 1279347	SSC Inconsistently Labeled in Plant	
CAP 1279342	SSC Needs Verification with Flood Analysis Model, PAB-923 Battery Room	
CAP 1276715	21 SSCs require Procurement per A.6, with Availability/Quantity not Assured	
CAP 1279348	SSC Removed for RFO25 Work	
CAP 1279350	Four Penetrations with Inadequate Seals	
CAP 1279352	Two SSCs could be Compromised by DBE	
CAP 1279356	SSC Located Onsite has Accessibility/Warehousing Concern	
CAP 1279358	Twenty-Two Doors Lack Flooding Labels	
CAP 1279361	Forty SSC/Areas could not be Surveyed due to Inaccessibility/Safety/Contaminated Area Concerns	

03.04 Assess the thoroughness of the licensee's walkdowns and inspections of important equipment needed to mitigate fire and flood events to identify the potential that the equipment's function could be lost during seismic events

Number	Description or Title	Date or Revision
B.08.05-05	Fire Protection – System Operation	Revision 49
Contractor Report 011C3956-RPT-001	Assessment of the Seismic Vulnerability of Fire Protection and Flood Mitigation Systems at the Monticello Nuclear Power Plant	Revision A
CAP 1278169	IER 1-11-1; Fire System Seismic Vulnerabilities	
CAP 1278243	Fire System Seismic Vulnerabilities, Hydrants	
CAP 1276324	Several Seismic Type Vulnerabilities have been Identified (B.5.b Equipment, Trucks, Pump, Fuel, Hoses Stored in Non-Seismic Building)	
CAP 1278594	Fires System Seismic Vulnerabilities,Transformers	
CAP 1280332	Receiving Warehouse Possible Seismic Damage (Inhibits Ability to get to Sandbags and Other Equipment)	
CAP 1280335	Perform Seismic Walkdown of Equipment that could not be Accessed during Initial Walkdown for IER 11-1	
CAP 1280337	Door 18 could be Compromised by Seismic Event	
CAP 1277358	IER 1-11; Vulnerability, Diesel Fire Pump	

LIST OF ACRONYMS USED

ADAMS	Agencywide Documents Access and Management System
AOP	Abnormal Operating Procedure
AMT	Accident Management Team
CAP	Corrective Action Program
CFR	Code of Federal Regulations
EDMG	Extensive Damage Mitigating Strategies
EOF	Emergency Operating Facility
EOP	Emergency Operating Procedure
ERO	Emergency Response Organization
HELB	High Energy Line Break
IP	Inspection Procedure
LMS	Learning Management System
MNGP	Monticello Nuclear Generating Plant
NRC	U.S. Nuclear Regulatory Commission
PARS	Publicly Available Records System
RFO	Refueling Outage
SAMG	Severe Accident Management Guideline
SBO	Station Blackout
SSC	Structure, System, and Component
SSE	Safe-Shutdown Earthquake
TSC	Technical Support Center

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Kenneth Riemer, Chief
Branch 2
Division of Reactor Projects

Docket No. 50-263
License No. DPR-22

Enclosure: Inspection Report 05000263/2011009

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Letter to T. O'Connor from K. Riemer dated May 13, 2011

SUBJECT: MONTICELLO NUCLEAR GENERATING PLANT – NRC TEMPORARY INSTRUCTION 2515/183 INSPECTION REPORT 05000263/2011009

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Exhibit C-2

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, IL 60532-4352

May 13, 2011

Mr. Mark A. Schimmel
Site Vice President
Prairie Island Nuclear Generating Plant
Northern States Power Company, Minnesota
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2 - NRC TEMPORARY INSTRUCTION 2515/183 INSPECTION REPORT 05000282/2011009; 05000306/2011009

Dear Mr. Schimmel:

On April 29, 2011, the U. S. Nuclear Regulatory Commission (NRC) completed an inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2, using Temporary Instruction 2515/183, "Followup to the Fukushima Daiichi Nuclear Station Fuel Damage Event." The enclosed inspection report documents the inspection results which were discussed on April 29, 2011, with you and other members of your staff.

The objective of this inspection was to promptly assess the capabilities of Prairie Island Nuclear Generating Plant to respond to extraordinary consequences similar to those that have recently occurred at the Japanese Fukushima Daiichi Nuclear Station. The results from this inspection, along with the results from this inspection performed at other operating commercial nuclear plants in the United States will be used to evaluate the U.S. nuclear industry's readiness to safely respond to similar events. These results will also help the NRC to determine if additional regulatory actions are warranted.

All of the potential issues and observations identified by this inspection are contained in this report. The NRC's Reactor Oversight Process will further evaluate any issues to determine if they are regulatory findings or violations. Any resulting findings or violations will be documented by the NRC in a separate report. You are not required to respond to this letter.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

John B. Giessner, Chief
Branch 4
Division of Reactor Projects

Docket Nos. 50-285; 50-306; 72-010
License Nos. DPR-42: DPR-60; SNM-2506

Enclosure: Inspection Report 05000282/2011009; 05000306/2011009

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-282; 50-306; 72-010
License Nos:	DPR-42; DPR-60; SNM-2506
Report No:	05000282/2011009; 05000306/2011009
Licensee:	Northern States Power Company, Minnesota
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	Welch, MN
Dates:	March 23, 2011, through April 29, 2011
Inspectors:	K. Stoedter, Senior Resident Inspector P. Zurawski, Resident Inspector S. Lynch, Nuclear Safety Professional Development Program Participant (observer)
Approved by:	John B. Giessner, Chief Branch 4 Division of Reactor Projects

SUMMARY OF FINDINGS

05000282/2011009; 05000306/2011009; 03/23/2011 – 04/29/2011; Prairie Island Nuclear Generating Plant, Units 1 and 2; Temporary Instruction 2515/183 - Followup to the Fukushima Daiichi Nuclear Station Fuel Damage Event.

This report covers an announced Temporary Instruction inspection. The inspection was conducted by resident inspectors.. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

INSPECTION SCOPE

The intent of the TI is to provide a broad overview of the industry's preparedness for events that may exceed the current design basis for a plant. The focus of the TI was on (1) assessing the licensee's capability to mitigate consequences from large fires or explosions on site, (2) assessing the licensee's capability to mitigate station blackout (SBO) conditions, (3) assessing the licensee's capability to mitigate internal and external flooding events accounted for by the station's design, and (4) assessing the thoroughness of the licensee's walk downs and inspections of important equipment needed to mitigate fire and flood events to identify the potential that the equipment's function could be lost during seismic events possible for the site. If necessary, a more specific follow-up inspection will be performed at a later date.

INSPECTION RESULTS

All of the potential issues and observations identified by this inspection are contained in this report. The NRC's Reactor Oversight Process will further evaluate any issues to determine if they are regulatory findings or violations. Any resulting findings or violations will be documented by the NRC in a separate report.

03.01 Assess the licensee's capability to mitigate conditions that result from beyond design basis events, typically bounded by security threats, committed to as part of NRC Security Order Section B.5.b issued February 25, 2002, and severe accident management guidelines and as required by Title 10 of the Code of Federal Regulations (10 CFR) 50.54(hh). Use Inspection Procedure (IP) 71111.05T, "Fire Protection (Triennial)," Section 02.03 and 03.03 as a guideline. If IP 71111.05T was recently performed at the facility the inspector should review the inspection results and findings to identify any other potential areas of inspection. Particular emphasis should be placed on strategies related to the spent fuel pool. The inspection should include, but not be limited to, an assessment of any licensee actions to:	
Licensee Action	**Describe what the licensee did to test or inspect equipment.**
a. Verify through test or inspection that equipment is available and functional. Active equipment shall be tested and passive equipment shall be walked down and inspected. It is not expected that permanently installed equipment that is tested under an existing regulatory testing program be retested. This review should be done for a reasonable sample of mitigating strategies/equipment.	The licensee identified equipment (active and passive) utilized for implementation of B.5.b actions and Severe Accident Management Guidelines (SAMGs). Permanent plant equipment (i.e., in situ equipment) was not considered within the scope of this inspection since it was normally in service, subjected to maintenance and surveillance activities, and/or checked on operator rounds. The licensee identified surveillances/tests and performance frequencies for the identified equipment and reviewed the most recent results. All active equipment within the scope defined above was retested. Passive equipment within the scope was inspected and inventoried using existing procedures.
	Describe inspector actions taken to confirm equipment readiness (e.g., observed a test, reviewed test results, discussed actions, reviewed records, etc.).
	The licensee's actions discussed above were completed prior to the issuance of NRC TI 2515/183. The inspectors assessed the adequacy of the licensee's actions and capabilities by reviewing the licensee's activities. This review consisted of reviewing the results of equipment testing activities to ensure B.5.b and SAMG-related equipment could perform as required. The inspectors also independently walked down and inspected major B.5.b and SAMG contingency response equipment staged throughout the site.
	Discuss general results including corrective actions by licensee.
	The licensee had only one piece of SAMG-related equipment that was not considered in situ plant equipment. Both the licensee and the inspectors verified that this piece of equipment was in good material condition and in the designated storage location. All designated B.5.b equipment (active and passive) was verified by the licensee and the inspectors to be in the proceduralized storage location. Minimum equipment inventories were also verified to be met. The licensee performed surveillance and/or preventive maintenance activities on specific passive equipment to verify that the equipment was ready for use. The licensee performed flow verification testing on the B.5.b pump to ensure that pump could supply required flows. The inspectors verified that the pump remained able to provide

	flow commensurate with the B.5.b strategies. Some minor equipment enhancements were identified by the licensee and entered into the corrective action program (CAP). Specific CAP documents are listed in the List of Documents Reviewed section of this report.
Licensee Action	**Describe the licensee's actions to verify that procedures are in place and can be executed (e.g. walkdowns, demonstrations, tests, etc.)**
b. Verify through walkdowns or demonstration that procedures to implement the strategies associated with B.5.b and 10 CFR 50.54(hh) are in place and are executable. Licensees may choose not to connect or operate permanently installed equipment during this verification. This review should be done for a reasonable sample of mitigating strategies/equipment.	The licensee formed a response team to evaluate whether B.5.b and SAMG-related procedures were in place and executable. The licensee's response team reviewed industry B.5.b and SAMG guidance, and performed a combination of walkdown and table top reviews, to validate that procedures for implementing the strategies associated with B.5.b and 10 CFR 50.54(hh) were in place and could be executed. The event response team also used a series of simulator scenarios plus a detailed table top review to evaluate the availability and execution of SAMG procedures. **Describe inspector actions and the sample strategies reviewed. Assess whether procedures were in place and could be used as intended.** A majority of the licensee's actions in this area were completed prior to the issuance of TI 2515/183. The inspectors observed portions of the licensee's SAMG table top review to assess whether the SAMG procedures were executable. The inspectors also assessed the licensee's execution capabilities by conducting a review of the licensee's walkdown activities. Based upon the results of a previous B.5.b inspection, the inspectors chose several B.5.b procedures for review. In each case, the inspectors performed an independent, in-plant walkdown to ensure that appropriate equipment was available, the procedure could be executed as written, and that previous NRC identified issues with the strategies had been corrected. The inspectors used the results of their independent review to verify the licensee's conclusions.

	Discuss general results including corrective actions by licensee.
	Operations personnel walked down each of the procedures used following a severe accident or B.5.b event to ensure that each action could be performed. No deficiencies were identified. However, enhancements such as the staging of bolt cutters and possible plant modifications to ease procedure execution were identified and documented in the CAP. During the performance of SAMG table top activities, the licensee identified an area for improvement regarding SAMG-related training. Specifically, the licensee identified that SAMG-related continuing training had not been provided to the necessary emergency response organization (ERO) members. The inspectors verified that the initial and continuing training program for all on-shift operations personnel included SAMG and B.5.b-related training. The inspectors also verified that all licensed and non-licensed operators qualified to stand watch had completed B.5.b and SAMG training. The licensee also completed a SAMG-related emergency drill every six years. The lack of SAMG continuing training for other ERO members resulted in extending the amount of time specific ERO members needed to implement the SAMG procedures. However, the SAMG procedures remained executable. The licensee documented this issue in their CAP. All CAP document numbers initiated as part of this review are provided in the List of Documents Reviewed section of this report.
Licensee Action	**Describe the licensee's actions and conclusions regarding training and qualifications of operators and support staff.**
c. Verify the training and qualifications of operators and the support staff needed to implement the procedures and work instructions are current for activities related to Security Order Section B.5.b and severe accident management guidelines as required by 10 CFR 50.54 (hh).	The licensee identified operator training/qualification requirements associated with the implementation of B.5.b or SAMG strategies. The licensee documented that operator training requirements were current and identified those operators with qualification requirements that were not current due to medical restrictions. The licensee also identified the B.5.b and SAMG training/qualification requirements for applicable ERO command and support staff and verified training requirements were current.
	Describe inspector actions and the sample strategies reviewed to assess training and qualifications of operators and support staff.
	The licensee's actions as discussed above were completed prior to the issuance of NRC TI 2515/183. The inspectors assessed the licensee's training and qualification activities by conducting a review of training and qualification materials and records related to B.5.b and SAMG event response.

	Discuss general results including corrective actions by licensee.
	The licensee reviewed the training program descriptions for all licensed and non-licensed operations personnel and determined that B.5.b and SAMG-related training was provided as part of the operations initial and continuing training programs. The licensee reviewed training qualification dates contained in their learning management system and verified that all operators qualified to stand watch had received the training required by the operator continuing training program within the specified frequency. The licensee confirmed that all operations personnel verify their qualifications prior to assuming an on-shift position. The training requirements, qualifications, and associated records needed for ERO command and support staff were also reviewed. While all ERO personnel had completed required training, the licensee identified that no training requirement existed to ensure that ERO personnel received continuing training on SAMG procedures on a specified frequency (see Section 03.01b above). This issue was documented in the licensee's CAP. The licensee was implementing activities to develop continuing training for SAMG decision makers and evaluators at the conclusion of this inspection.
Licensee Action	**Describe the licensee's actions and conclusions regarding applicable agreements and contracts are in place.**
d. Verify that any applicable agreements and contracts are in place and are capable of meeting the conditions needed to mitigate the consequences of these events. This review should be done for a reasonable sample of mitigating strategies/equipment.	The licensee identified all applicable contracts and agreements committed to be in place for the mitigation of a B.5.b related event. The licensee verified that the contracts and agreements were current and documented whether or not the contracts/agreements were capable of meeting the mitigation strategy.
	For a sample of mitigating strategies involving contracts or agreements with offsite entities, describe inspector actions to confirm agreements and contracts are in place and current (e.g., confirm that offsite fire assistance agreement is in place and current).
	The licensee's actions as discussed above were completed prior to the issuance of NRC TI 2515/183. The inspectors assessed the licensee's capabilities by conducting an independent review of the agreements and contracts. The inspectors' determined that the agreements and contracts were current and adequate for meeting the licensee's mitigation strategy.

	Discuss general results including corrective actions by licensee.
	The licensee reviewed all contracts and agreements to ensure that the documents were current and that all required equipment covered by these documents remained available. An additional agreement was in place with the National Guard should an event extend beyond the capabilities of the agreed upon resources and/or local and state government.
Licensee Action	**Document the corrective action report number and briefly summarize problems noted by the licensee that have significant potential to prevent the success of any existing mitigating strategy.**
e. Review any open corrective action documents to assess problems with mitigating strategy implementation identified by the licensee. Assess the impact of the problem on the mitigating capability and the remaining capability that is not impacted.	CAP 1276003 – Re-Evaluate Continuing Training Requirements for SAMG Training CAP 1276437 – EDMG Portable Pump and Tow Vehicle Stuck in Mud CAP 1276441 – EDMG Portable Fire Pump Priming Issues during TP-1423 CAP 1276445 – EDMG Portable Fire Pump Suction Gauge not Functioning CAP 1276645 - Desired Equipment and Possible Modifications to Enhance SAMG Implementation CAP 1277505 – Enhancements to SAMG Procedures CAP 1276723 – Type on Equipment Availability Check Figure CAP 1277744 – Enhancement to SAMG Diagnostic Flow Chart CAP 1278970 – No Plywood Mats Available for use if Equipment Placed on Soft Ground The inspectors reviewed each CAP for potential impact to the licensee's mitigation strategies. No significant impacts were identified. While the inspectors were concerned regarding the licensee's lack of SAMG continuing training for ERO personnel, the inspectors observed portions of the licensee's SAMG table top activities and verified that currently qualified ERO staff members (SAMG decision makers and evaluators) were able to execute the SAMG procedures.

03.02 Assess the licensee's capability to mitigate station blackout (SBO) conditions, as required by 10 CFR 50.63, "Loss of All Alternating Current Power," and station design, is functional and valid. Refer to TI 2515/120, "Inspection of Implementation of Station Blackout Rule Multi-Plant Action Item A-22" as a guideline. It is not intended that TI 2515/120 be completely reinspected. The inspection should include, but not be limited to, an assessment of any licensee actions to:

Licensee Action	Describe the licensee's actions to verify the adequacy of equipment needed to mitigate an SBO event.
a. Verify through walkdowns and inspection that all required materials are adequate and properly staged, tested, and maintained.	Following an SBO event, Prairie Island procedures direct operations personnel to provide alternate AC to the SBO unit via the opposite unit's emergency diesel generators (EDG). As a result, there was no temporary or staged equipment needed to respond to an SBO event. The licensee reviewed recent EDG test results to verify that each EDG had been adequately tested. The licensee also performed a review of test results and calculations to determine that each EDG had the capacity to provide alternate AC during an SBO event. The licensee reviewed the electrical distribution system to ensure that alternate AC could be aligned to the SBO unit within required timeframe. Condensate and EDG fuel oil inventories were reviewed to verify that adequate inventories were maintained. Various plant support systems were also reviewed to ensure that power would be available to this equipment following the alignment of alternate AC. Operations personnel performed walkdowns of procedures used to respond to an SBO event to ensure that the procedures were adequate and executable. The licensee also conducted a review of open CAP items for potential SBO equipment impact.
	Describe inspector actions to verify equipment is available and useable.
	The inspectors assessed the licensee's capability to mitigate SBO conditions by conducting a review of the licensee's activities. The inspectors selected a sample of equipment utilized for mitigation of a SBO and conducted independent walkdowns of that equipment to verify that the equipment was properly aligned. The sample of equipment selected by the inspectors included, but was not limited to, EDGs and auxiliaries. The inspectors also observed recent surveillance testing (including a 24 hour load test) on two EDGs to ensure that this equipment was able to perform its safety function.

	Discuss general results including corrective actions by licensee.
	In general, the licensee's reviews verified that SBO equipment was ready to respond to a SBO condition. During their CAP review, however, the licensee noted multiple previously identified equipment issues on SBO support equipment which were not yet corrected. The inspectors were aware of each equipment issue identified by the licensee. The licensee had previously evaluated each condition using their prompt and immediate operability program. Functionality/Operability of the equipment was maintained in all cases. However, some cases required the implementation of compensatory measures. The inspectors reviewed each of the previously identified issues and determined that they would not prevent the licensee from responding to an SBO event. Corrective action program document numbers for each of the previously identified equipment issues are provided in the List of Documents Reviewed section of this report.
Licensee Action	**Describe the licensee's actions to verify the capability to mitigate an SBO event.**
b. Demonstrate through walkdowns that procedures for response to an SBO are executable.	The licensee conducted walkthroughs of SBO-related procedures with operations personnel to ensure the procedures were able to be executed without difficulty. In addition, the licensee performed several simulator scenarios using SBO-related procedures during the development of a risk assessment for one of the previously identified equipment issues.
	Describe inspector actions to assess whether procedures were in place and could be used as intended.
	The inspectors assessed the licensee's capabilities by conducting a review of the licensee's walk through activities. The inspectors selected several sections of procedures walked through by the licensee and performed an independent review to verify the licensee's conclusions. The inspectors also observed several of the licensee's simulator scenarios. Through these simulator observations, the inspectors concluded that the SBO-related procedures utilized had been in place for some time and were fully executable.
	Discuss general results including corrective actions by licensee.
	The licensee concluded that all procedures used to respond to an SBO event were executable. One CAP document was written regarding the need to evaluate whether some equipment should be labeled as emergency use only. However, this did not impact the licensee's ability to execute the SBO procedures. The CAP document number for this issue is provided in the List of Documents Reviewed section of this report.

03.03 Assess the licensee's capability to mitigate internal and external flooding events required by station design. Refer to IP 71111.01, "Adverse Weather Protection," Section 02.04, "Evaluate Readiness to Cope with External Flooding" as a guideline. The inspection should include, but not be limited to, an assessment of any licensee actions to verify through walkdowns and inspections that all required materials and equipment are adequate and properly staged. These walkdowns and inspections shall include verification that accessible doors, barriers, and penetration seals are functional.		
Licensee Action		**Describe the licensee's actions to verify the capability to mitigate existing design basis flooding events.**
a. Verify through walkdowns and inspection that all required materials are adequate and properly staged, tested, and maintained.		The licensee reviewed the design and licensing bases for both internal and external flooding. Licensee actions included reviewing flooding related procedures and identifying equipment and penetration seals utilized/required for flood mitigation. The licensee walked down flooding related equipment to ensure it was adequate and properly staged. Flood related doors, bulk heads, barriers, penetration seals and equipment were identified. The licensee verified that this equipment was routinely inspected for functionality. Where routine inspections were not performed or could not be relied upon to ensure functionality, the licensee performed walkdowns and inspections to ensure that the components were functional. The licensee had also installed several in-plant modifications to address internal flooding vulnerabilities within the turbine building. The licensee verified that these modifications remained in good condition and provided appropriate protection during a flooding event.
		Describe inspector actions to verify equipment is available and useable. Assess whether procedures were in place and could be used as intended.
		The inspectors assessed the licensee's capabilities to mitigate flooding by conducting a review of the licensee's walkdown activities. In several instances, these reviews involved the inspectors accompanying licensee personnel during their walkdowns. The inspectors also conducted independent walkdowns of selected flood mitigation equipment as part of the overall assessment of the licensee's flood mitigating capabilities. Licensee flood mitigation procedures were reviewed to verify usability. The inspector's conclusions aligned with the results obtained by the licensee.
		Discuss general results including corrective actions by licensee.
		The licensee's verification of flood mitigation capability consisted of procedure reviews and walk downs to verify that the systems, structures, and components (SSCs) were present, periodically tested, and in acceptable condition. All design features, such as flood barriers, were present and in good condition with exceptions documented in the licensee's corrective action system. The licensee initiated several CAPs to document degraded seals. For these instances, the licensee's assessment of operability, which was reviewed by the inspectors,

	determined that the missing seal did not have any significant adverse impact on flood mitigation capability. The licensee used plant specific design information to determine doors, barriers, and penetration seals that were required to remain functional to mitigate a flooding event. The licensee's reviews confirmed that all flood doors were inspected as part of a routine maintenance program. The licensee walked down other flood barriers and identified some internal flooding discharge paths that were not consistent with calculations/evaluations of record. The licensee evaluated these inconsistencies and determined that no operability issue existed. Independent assessment by the inspectors concluded similar results. Previous to this inspection, the licensee identified two additional flood barrier doors which had bottom seals that functioned intermittently. The licensee had previously established compensatory measures for each of these doors. Inspector review confirmed compensatory measures remained in place as of the date of this inspection. Additionally, the licensee identified a flood barrier penetration seal with a loose boot clamp. The licensee implemented actions to correct the problem by tightening the clamp. Other minor issues were noted by the licensee as part of the walkdown activities. A list of items placed in the corrective action system is provided in the List of Documents Reviewed section of this inspection report.

03.04 Assess the thoroughness of the licensee's walkdowns and inspections of important equipment needed to mitigate fire and flood events to identify the potential that the equipment's function could be lost during seismic events possible for the site. Assess the licensee's development of any new mitigating strategies for identified vulnerabilities (e.g., entered it in to the corrective action program and any immediate actions taken). As a minimum, the licensee should have performed walkdowns and inspections of important equipment (permanent and temporary) such as storage tanks, plant water intake structures, and fire and flood response equipment; and developed mitigating strategies to cope with the loss of that important function. Use IP 71111.21, "Component Design Basis Inspection," Appendix 3, "Component Walkdown Considerations," as a guideline to assess the thoroughness of the licensee's walkdowns and inspections.

Licensee Action	**Describe the licensee's actions to assess the potential impact of seismic events on the availability of equipment used in fire and flooding mitigation strategies.**
a. Verify through walkdowns that all required materials are adequate and properly staged, tested, and maintained.	The licensee identified equipment utilized/required for mitigation of fire and flood events. Industry seismic experts conducted walkdowns of fire and flood mitigating SSCs to determine whether this equipment would remain available following a safe shutdown earthquake. Seismic vulnerabilities, including storage locations, were identified, along with mitigating strategies for equipment that was not seismically qualified.

	Describe inspector actions to verify equipment is available and useable. Assess whether procedures were in place and could be used as intended.
	The inspectors conducted walkdowns, both independently and in conjunction with licensee personnel, of important SSCs needed to mitigate fire and flood events to identify the potential that the SSC's function could be lost during a seismic event. This equipment included, but was not limited to: • all major B.5.b contingency response equipment; • all installed fire protection and suppression equipment in the turbine building; • the installed diesel and electric fire pumps and their controls; and • water tight doors, roof hatches and floor plugs at the plant screenhouse. The results of the inspectors' reviews aligned with the licensee's conclusions that there were a number of seismic vulnerabilities that potentially need to be addressed, as described below.
	Discuss general results including corrective actions by licensee. Briefly summarize any new mitigating strategies identified by the licensee as a result of their reviews.
	Seismically qualified SSCs normally consist of safety-related equipment that has been formally qualified to function during and after a design basis earthquake. The licensee's reviews for this issue determined that nonsafety-related SSCs, in general, were not considered to be either seismically qualified or seismically rugged due to a wide variety of issues. A majority of installed sump pumps and flooding detectors were not designed as seismically qualified and have not been evaluated as being seismically rugged. However, a majority of the sump pumps and flooding detectors were not relied upon following a seismic/flooding event. Similarly, the vast majority of the fire protection system was not designed to be seismically qualified and could not be considered seismically rugged. Firefighting equipment staged to respond to B.5.b events was not stowed in seismically qualified buildings and locations, as a seismic event and B.5.b event have never been assumed to occur concurrently. The licensee's reviews identified instances where response capability could be enhanced. These included reviewing the locations of portable equipment and reviewing the need for supplemental portable equipment to compensate for the possible loss of much of the fire protection system.

		Further, reviews by the licensee identified that in the event of a postulated earthquake equipment may not function properly due to loss of essential power or being subjected to physical displacement. The existing mitigation strategy was considered presently sufficient by the licensee. Further mitigation strategies may be developed and implemented following a review of industry lessons learned from the Fukushima Daiichi event. The licensee entered the issues identified into their CAP as CAPs 1280101 and 1280380; INPO ER L1 11-1: Recommendation 4 Vulnerabilities and Enhancements.

Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. S. Northard and other members of licensee management at the conclusion of the inspection on April 29, 2011. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

M. Schimmel, Site Vice President
K. Davison, Plant Manager
T. Roddey, Site Engineering Director
J. Anderson, Regulatory Affairs Manager
C. Bough, Chemistry and Environmental Manager
B. Boyer, Radiation Protection Manager
K. DeFusco, Emergency Preparedness Manager
D. Goble, Safety and Human Performance Manager
J. Hamilton, Security Manager
J. Lash, Nuclear Oversight Manager
M. Milly, Maintenance Manager
J. Muth, Operations Manager
S. Northard, Performance Improvement Manager
K. Peterson, Business Support Manager
A. Pullam, Training Manager
R. Womack, Production Planning Manager (Acting)

Nuclear Regulatory Commission

J. Giessner, Chief, Reactor Projects Branch 4
T. Wengert, Project Manager, NRR

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

03.01 Assess the licensee's capability to mitigate conditions that result from beyond design basis events

Number	Description or Title	Date or Revision
CAP 1276003	Re-Evaluate Continuing Training Requirements for SAMG Training	March 18, 2011
CAP 1276437	EDMG Portable Pump and Tow Vehicle Stuck in Mud	March 20, 2011
CAP 1276441	EDMG Portable Fire Pump Priming Issues during TP-1423	March 20, 2011
CAP 1276445	EDMG Portable Fire Pump Suction Gauge not Functioning	March 20, 2011
CAP 1276645	Desired Equipment and Possible Modifications to Enhance SAMG Implementation	March 22, 2011
CAP 1277505	Enhancements to SAMG Procedures	March 26, 2011
CAP 1276723	Typo on Equipment Availability Check Figure	March 22, 2011
CAP 1277744	Enhancement to SAMG Diagnostic Flow Chart	March 28, 2011
CAP 1278970	No Plywood Mats Available for use if Equipment Placed on Soft Ground	April 4, 2011
TP 1422	Quarterly EDMG Equipment Inventory	March 20, 2011
TP 1423	Portable Diesel Fire Pump Testing	March 20, 2011
SP 1183.2	Monthly Fire Extinguisher and Hose Station Inspection	March 11, 2011
SP 1664	Monthly Fire Fighting Equipment Check	March 24, 2011
EDMG-1	Guideline Response to a Loss of Normal Plant Command and Control	Revision 2
EDMG-2	Guideline for Damage Mitigation Strategies	Revision 3
SEG P9160S-001	SAMG Technical Support Center Walkthrough	March 21, 2011
1(2)SACRG-1	Severe Accident Control Room Guideline 1	Revision 0

1(2)SAG-1	Inject into the Steam Generators	Revision 2
1(2)SAG-2	Depressurize the Reactor Coolant System	Revision 1
1(2)SAG-3	Inject into the Reactor Coolant System	Revision 1
1(2)SAG-4	Inject into Containment	Revision 0
1(2)SAG-5	Reduce Fission Product Releases	Revision 0
1(2)SAG-6	Control Containment Conditions	Revision 0
1(2)SAG-7	Reduce Containment Hydrogen	Revision 0
1(2)SCG-1	Mitigate Fission Product Releases	Revision 0
1(2)SCG-2	Depressurize Containment	Revision 0
1(2)SCG-3	Control Hydrogen Flammability	Revision 0
1(2)SCG-4	Control Containment Vacuum	Revision 0
1(2)SAEG-1	TSC Long Term Monitoring	Revision 0
1(2)SAEG-2	Unit 1 SAMG Termination	Revision 0
1(2)CA-1	RCS Injection to Recover Core	Revision 0
1(2)CA-2	Injection Rate for Long Term Decay Heat Removal	Revision 0
1(2)CA-3	Hydrogen Flammability in Containment	Revision 1
1(2)CA-4	Volumetric Release Rate from Containment	Revision 0
1(2)CA-5	Containment Water Level and Volume	Revision 0
1(2)CA-6	RWST Gravity Drain	Revision 0
1(2)CA-7	Hydrogen Impact when Depressurizing Containment	Revision 0
FL-LOR-TPD	Fleet Licensed Operator Requalification Training Program Description	Revision 2
FL-ILT	Initial License Training	December 9, 2010
PI-OPS-ILT	Prairie Island Initial License Training	Revision 10
P7480-002	SAMG Executive Volume for the Control Room Lesson Plan	Revision 0

P7480L-004	Severe Accident Control Room Guideline for Transients After TSC is Functional Lesson Plan	Revision 0
P7482L-001	SAMG Executive Volume for the TSC Lesson Plan	Revision 0
P7482L-003	SAMG Instrumentation Lesson Plan	Revision 0
P7482L-004	SACRG-1 and 2 for the Technical Support Center	Revision 0
P9110L-0802	EDGM and SAMG Review	Revision 0
PI-NLO	Prairie Island Nuclear Generating Plant Non-Licensed Operator Training Program Description	Revision 19
PI-P7480L-005	Extensive Damage Mitigation Guideline Phase 2 and 3	Revision 0
P8450L-002	Goodwin Portable Diesel-Driven Water Pump	Revision 0
PI-P8410L-0403	Extensive Damage Mitigation Guidelines	Revision 0

03.02 Assess the licensee's capability to mitigate station blackout (SBO) conditions

Number	Description or Title	Date or Revision
CAP 1174370	No Tornado Protection of CC Piping for 122 Spent Fuel Pool Heat Exchanger	March 23, 2009
CAP 1214553	Inadequate Design Basis for Battery Load Profile/Duty Cycle	January 20, 2010
CAP 1233935	Potential Common Mode Failure of Unit 2 Fuel Oil Transfer Pumps	May 21, 2010
CAP 1234078	Possible Non-Conservative Assumption in ENG-ME-066	May 23, 2010
CAP 1238842	CDBI 2010 Prep SP1083 Revised without Proper 50.59 Evaluation	June 24, 2010
CAP 1248977	12 AFW Pump Unit Cooler Leaking	September 9, 2010
CAP 1250561	Battery Chargers may Stop Operating if Undervoltage Setpoint is Reached	September 21, 2010
CAP 1263345	Operability Recommendation 1233935-01 Diesel Fuel Oil Needs Improvement	December 17, 2010
CAP 1265904	Battery Room Heatup did not Consider Historical Information	January 11, 2011
CAP 1266815	Extent of Condition on Room Heat Up Issues	January 18, 2011
CAP 1270101	Questions regarding Operability Recommendation 1263345-01	February 9, 2011
CAP 1270104	Non-Conservative Assumption in Unit 1 Battery Calculations	February 9, 2011

CAP 1271778	Items need to be Analyzed for SP 1039 Tornado Hazards	February 20, 2011
CAP 1271871	Items Identified in SP 1039 Areas 1 and 2 Removed/Secured	February 21, 2011
CAP 1277162	Battery Charger Significance Determination Process Identified other Lockup Scenarios	March 24, 2011
CAP 1277409	Valves not Easily Accessible	March 25, 2011
CAP 1278211	Consider Labeling Equipment as Emergency Use Only	March 30, 2011
NUMARC 87-00	Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors	August 1991
Regulatory Guide 1.155	Station Blackout	August 1988
NRC Letter	Safety Evaluation of the Prairie Island Nuclear Generating Plant Units 1 and 2; Station Blackout Rule 10 CFR 50.63	Sept. 18, 1990
Section 8	Prairie Island Updated Safety Analysis Report	Revision 32P
ENG-EE-045	Diesel Generator Steady State Loading for a LOOP Coincident with an SBO	Revision 5
1(2)ECA-0.0	Loss of All Safeguards AC Power	Revision 20
SP 1(2)001B	Unit 1(2) Control Room Log Modes 1 and 2	Revision 15
SP 1187	Weekly Battery Inspection	Revision 27
SP 1039	Tornado Hazard Site Inspection	March 20, 2011
AB-2	Tornado/Severe Thunderstorm/High Winds	Revision 35
1(2)C20.5	Unit 1(2) – 4.16 kV System	Revision 15/20
2C20.5 AOP1	Re-Energizing 4.16 kV Bus 25	Revision 11
2C20.5 AOP4	Re-Energizing 4.16 kV Bus 25 via Bustie Breaker	Revision 4
SP 1322	Safeguards Buses Weekly Inspection	March 23, 2011
SP 2322	Safeguards Buses Weekly Inspection	March 22, 2011
SP 1093	D1 Diesel Generator Monthly Slow Start Test	March 14, 2011
SP 1295	D1 Diesel Generator 6 Month Fast Start Test	March 14, 2011
SP 1334	D1 Diesel Generator 18 Month 24 Hour Load Test	January 14, 2010
SP 1305	D2 Diesel Generator Monthly Slow Start Test	February 28, 2011
SP 1307	D2 Diesel Generator 6 Month Fast Start Test	Sept. 22, 2010

SP 1335	D2 Diesel Generator 18 Month 24 Hour Load Test	January 26, 2011
SP 2295	D5 Diesel Generator 6 Month Fast Start Test	December 6, 2010
SP 2334	D5 Diesel Generator 18 Month 24 Hour Load Test	August 29, 2009
SP 2305	D6 Diesel Generator Monthly Slow Start Test	March 23, 2011
SP 2307	D6 Diesel Generator 6 Month Fast Start Test	October 18, 2010
SP 2335	D6 Diesel Generator 18 Month 24 Hour Load Test	June 11, 2009

03.03 Assess the licensee's capability to mitigate internal and external flooding events required by station design

Number	Description or Title	Date or Revision
CAP 1275453	Response To IER L1-11-1 Fukushima Daiichi Nuclear Station Fuel Damage Caused by Earthquake and Tsunami	April 6, 2011
CAP 1276007	Operational Decision Making for 12 DDCLP Preventive Maintenance During Flood Window	March 18, 2011
CAP 1276379	Discrepancy between TP 1539 and C25.1	March 20, 2011
CAP 1276479	Procedures Still Reference Use of Land-Lock Discharge	March 21, 2011
CAP 1276585	Piles of pallets and Debris on South Side of Protected Area	March 21, 2011
CAP1276812	Outside Satellite RCAs Inadequate	March 22, 2011
CAP 1276916	Station Flood Procedure (AB-4) Level for Shutdown challenged	March 23, 2011
CAP 1277010	SFGD CL Bay Levels Read Too High	March 23, 2011
CAP 1277180	Flooding Concerns Itemized List	March 24, 2011
CAP 1277329	Discrepancy in AB-4 Flood Procedure and USAR - 1000 Year Flood	March 25, 2011
CAP 1277778	Ensure Completion of Screens to Fine Mesh Mode	March 28, 2011
CAP 1277988	AB-4 Flood Concerns for Medium Voltage Cable Splice Vault	March 29, 2011
CAP 1278018	121 MDCLP Baseplate Drain Hole Threads Appear Inadequate	March 29, 2011
CAP 1278029	Unclear Labeling of Flood Cover for CT Pumphouse Roof	March 29, 2011
CAP 1278031	Respond to Violation Associated with Turbine Bldg Flooding	March 29, 2011
CAP 1278082	Intake Screenhouse Discharge Trough is Plugged	March 29, 2011

CAP 1278437	Unit-2 Condenser Cleaning	April 1, 2011
CAP 1278538	Deicing Pumphouse Standpipe Overflow is Discharging to River	April 1, 2011
CAP 1278562	Road to Fish Pit Covered by Water	April 1, 2011
CAP 1278970	Walkdown of AB-4 Flood	April 4, 2011
CAP 1279054	No Functional Sump Pumps In CTPH During Flood Conditions	April 4, 2011
CAP 1279198	REMP TLD changeout affected by Miss. River Flooding	April 5, 2011
CAP 1279293	SP 1333 Completed UNSAT Due to AB-4, Flooding	April 6, 2011
CAP 1279430	Unclear Direction in AB-4 for Powering Equipment after LOOP;	April 6, 2011
CAP 1279562	Underground Splice Vault Flooding Potential	April 7, 2011
CAP 1279620	AB-4 Does Not ID What Size Portable Sump Pumps are Needed	April 7, 2011
CAP 1279684	Discharge Canal Level Indication Erratic	April 8, 2011
CAP 1280421	Riverside Training Class Canceled Due To Flooding	April 13, 2011
CAP 1280473	Technical Review Pending on Internal Flooding Evaluations	April 13, 2011
CAP 1280489	Neutralization Tanks Need to be Emptied of Water	April 13, 2011
CAP 1280574	No Clear Guidance to Power Plant Equipment During LOOP	April 13, 2011
CAP 1280653	External Flood Penetrations - No Specific Discussion in PM 3586-10	April 14, 2011
CAP 1275668	AB-4 Revision 36 Update Table-1	March 16, 2011
CAP 1278027	AB-4 Flood Revision 37	March 29, 2011
CAP 1278167	AB-4, Revision 37	March 30, 2011
CAP 1280475	AB-4, Revision 37	April 13, 2011
	INPO IER L1-11-1, "Fukushima Daiichi Nuclear Station Fuel Damage Caused by Earthquake and Tsunami"	March 15, 2011
Appendix F	Prairie Island Updated Safety Analysis Report (USAR), "Probable Maximum Flood Study Mississippi River at Prairie Island, Minnesota"	Revision 4
Section 2	Prairie Island USAR "Site and Environs"	Revision 31
	Letter, A Giambusso to AV Dienhart, "Request for Additional Information Concerning a Postulated Steam Pipe Break Outside of Containment"	December 12, 1972

	Prairie Island Final Safety Analysis Report (FSAR).	Amendment 31
	Supplement 1 to Safety Evaluation by the Directorate of Licensing U. S. Atomic Energy Commission in the matter of Northern States Power Company Prairie Island Units 1 & 2 Docket Nos. 50-282 & 50-306	March 21, 1973
	NRC Office of Nuclear Reactor Regulation Letter to NRC Region III, Task Interface Agreement - Evaluation of Flooding Licensing Basis at PINGP (TIA 2011-007, NRC Adams #ML110240359)	January 28, 2011
	PINGP HELB Reconstitution Project Study	Revision 0
ENG-ME-758	Evaluation of HELB Target Flow Rates in the Turbine Building	Revision 0
ENG-ME-732	Determination of HELB / Flooding Interactions in the Turbine Building	Revision 1
ENG-ME-759	GOTHIC Internal Flooding Calculation for the Turbine Building,	Revision 0
ENG-ME-448	Auxiliary Building Flooding Analysis	Revision 1
Section 6	Prairie Island USAR "Engineered Safety Features"	Revision 32P
	Letter from Skovholt (AEC) to Dienhart (NSP), Subject: "Flooding of Critical Equipment,"	August 3, 1972
	Letter from DeYoung (AEC) to Dienhart (NSP), Subject: "Plant Flooding,"	September 26, 1972
	Letter from Dienhart (NSP) to DeYoung (AEC), Subject: "30 day response to the 9/26/1972 letter,"	October 23, 1972.
86L907	Modification 86L907, "High Turbine Building Level Trip of the Circulating Water Pumps."	
AB-4	Floods	Revision 37
PINGP 195	Turbine Building Data - Unit 1	Revision 99
PINGP 196	Turbine Building Data - Unit 2	Revision 113
TP 1398	Verify Physical Inputs To Internal Flooding Evaluations	Revision 2
EC 16940	Engineering Change (EC) 16940 - Condenser Pit Fill Time due to a Random Pipe Failure	
	Letter, A Giambusso to AV Dienhart, "Clarification of Guidelines and Criteria Regarding a Postulated Break in a Pipe Carrying a High-Energy Fluid"	January 11, 1973
Generic Letter 87-11	Relaxation In Arbitrary Intermediate Pipe Rupture Requirements	June 19, 1987
USAR	Prairie Island Updated Safety Analysis Report (USAR), Appendix I, "High Energy Line Breaks Outside of Containment"	Revision 32P
OPR 1178236	Turbine Building HELB	November 1, 2009

C1-A	Unit Heatup Checklist	Revision 25
C35 AOP1	Abnormal Operating Procedure, Loss Of Pumping Capacity Or Supply Header With SI	Revision 12
C35 AOP2	Abnormal Operating Procedure, Loss Of Pumping Capacity Or Supply Header Without SI	Revision 12
C35 AOP5	Abnormal Operating Procedure, Cooling Water Leakage Outside Containment	Revision 7
5AWI 8.9.0	Internal Flooding Drainage Control	Revision 7
H36	Plant Flooding	Revision 4
C31 AOP1	Fire Protection Line Break	Revision 0
C47019	Alarm Response Procedure for Annunciator Location: 47019-0603 - AUX BLDG SUMP HI LVL	Revision 31
C47020	Alarm Response Procedure for Annunciator Location: 47020-0303 - CC AREA SUMP HI LVL	Revision 40
C47016	Alarm Response Procedure for Annunciator Location: 47016-0602 - 11 RHR PIT SUMP HI/LO LVL	Revision 41
C47016	Alarm Response Procedure for Annunciator Location: 47016-0603 - 12 RHR PIT SUMP HI/LO LVL	Revision 41
C47516	Alarm Response Procedure for Annunciator Location: 47516-0602 - 21 RHR PIT SUMP HI/LO LVL	Revision 38
C47516	Alarm Response Procedure for Annunciator Location: 47516-0603 - 22 RHR PIT SUMP HI/LO LVL	Revision 38
C47022	Alarm Response Procedure for Annunciator Location: 47022-0305 - 122 FIRE PUMP (DIESEL) RUNNING	Revision 46
C47008	Alarm Response Procedure for Annunciator Location: 47008-0606 - TURBINE ROOM SUMP HI LVL	Revision 25
C47508	Alarm Response Procedure for Annunciator Location: 47508-0606 - TURBINE ROOM SUMP HI LVL	Revision 25
C47001	Alarm Response Procedure for Annunciator Location: 47001-0102 - CDSR PIT FLOODING CHANNEL ALERT	Revision 15
C47501	Alarm Response Procedure for Annunciator Location: 47501-0104 - CDSR PIT FLOODING CHANNEL ALERT	Revision 25
C47020	Alarm Response Procedure for Annunciator Location: 47020-0104 - LOOP A COOLING WATER HI FLOW	Revision 35
C47020	Alarm Response Procedure for Annunciator Location: 47020-0105 - LOOP B COOLING WATER HI FLOW	Revision 35
C47020	Alarm Response Procedure for Annunciator Location: 47020-0204 - LOOP A COOLING WATER LO PRESS	Revision 35
C47020	Alarm Response Procedure for Annunciator Location: 47020-0205 - LOOP B COOLING WATER LO PRESS	Revision 35
C47520	Alarm Response Procedure for Annunciator Location: 47520-0103 - LOOP A COOLING WATER HI FLOW	Revision 32
C47520	Alarm Response Procedure for Annunciator Location: 47520-0104 - LOOP B COOLING WATER HI FLOW	Revision 32
C47520	Alarm Response Procedure for Annunciator Location: 47520-0203 - LOOP A COOLING WATER LO PRESS	Revision 32

C47520	Alarm Response Procedure for Annunciator Location: 47520-0204 - LOOP B COOLING WATER LO PRESS	Revision 32
C47001	Alarm Response Procedure for Annunciator Location: 47001-0605 - SCRNHSE SUMP HI LA	Revision 15
EC 8754	Evaluate the Relay & Cable Spreading Room for Internal Flooding	
EC 8975	Evaluate the U1 4.16kV & 480V Sfgds Switchgear Compartment for Internal Flooding	
EC 9069	EC 9069, Evaluate D1/D2 Compartments for Internal Flooding	
EC 8070	Evaluate D5/D6 Compartments for Internal Flooding	
EC 9076	Evaluate the 480V Sfgds Switchgear (Bus 112 & 122) & Event Monitoring Rooms for Internal Flooding	
EC 9377	Evaluate 121 & 122 CR Chiller Rooms for Internal Flooding	
EC 9538	Engineering Change (EC) 9538, Evaluate the Control Room Compartment for Internal Flooding	
WO 352018	IC 0WL-7, Auxiliary Building and Radwaste Building Sump Level Alarm Calibration	September 11, 2008
WO 326402	IC 0WL-14, 11 RHR Pit Sump Level Switch Calibration	May 2, 2008
WO 326423	IC 0WL-15, 12 RHR Pit Sump Level Switch Calibration	June 12, 2008
WO 323413	IC 0WL-16, 21 RHR Pit Sump Level Switch Calibration	January 25, 2008
WO 326422	PMRQ 6956-01, IC 0WL-17, 22 RHR Pit Sump Level Switch Calibration	December 6, 2007.
WO 391442	IC 1MD-1, Turbine Building Sump Level Alarm Calibration	December 7, 2010.
WO 391439	IC 2MD-1, Turbine Building Sump Level Switch Calibration	December 15, 2010.
WO 290501	PE 0023-03T, Bus 23 Relay Test Trip	May 10, 2010.
WO 309081	PE 0013-10T, 4.16 kV Bus 23 Cubicle 3 21 Circulating Water Pump Electrical Maintenance Test Tripping	Revision 5
WO 389705	ICPM 1-027, Loop A Cooling Water Header Instrument Calibration	January 7, 2010.
WO 385792	ICPM 2-027, Loop B Cooling Water Header Instrument Calibration	November 24, 2009.
WO 389490	IC 0CL-1, 122 Filtered Water Strainer Differential Pressure and Cooling Water Strainer Pressure Alarm Calibration	October 1, 2010
W O 391441	IC 1MD-3, Screen House Sump Level Alarm Calibration	December 7, 2010
WO 412783	TP 1398, Verify Physical Inputs To Internal Flooding Evaluations	March 28, 2011
TP 1398	Verify Physical Inputs To Internal Flooding Evaluations	Revision 2
WO 407939	SP 1293, Inspection of Flood Control Measures	February 3, 2011

SP 1293	Inspection of Flood Control Measures	Revision 20
21-6197	Fuel Oil Storage Tank Seismic Review	October 3, 1969
CAP 1278023	Replace AB-4 Flood Tag for Baseplate Drain Cap on 12 DDCLP	March 29, 2011
CAP 1273163	AB-4 Revision 36 EC 15219	March 01, 2011
WO 409082	Possible Blown Bearing on 22 Turbine Building Sump	December 13, 2010
WO 391977	11 Condensate Pit Sump Pump Not Running	October 22, 2009
WO 419454	Repair 122 Cooling Tower Sump Pump – Won't Stop Running	April 07, 2011
WO 373749	121 Cooling Tower Pump House Sump Pump Tripped on Overload	March 09, 2009
WO 424459	Fabricate Strongback for AB-4	March 15, 2011
WR 66127	Refurbish Degraded Cooling Tower Pump House Flood Cover Eyebolts	March 30, 2011
WR 66128	Inspect D5 and D6 Loop Seal Blind Flange Connections	March 30, 2011
CAP 1279430	Unclear Direction in AB-4 for Powering Equipment after LOOP	April 06, 2011
WR 66353	Repair Cooling Tower Pumphouse Drop Area Cover Lifting Eye Hooks	April 06, 2011
WR 66098	Baseplate Drain Hole Threads Need To Be Cleaned Up	March 29, 2011
CAP 1277095	Radio Tower Backup Generator Fuel Level Less Than 40%	March 24, 2011
CAP 1275179	Flooding Response and Logistics Plan Tracking	March 14, 2011
CAP 1274249	OE31675 Inadequate Procedures to Protect Against flooding	March 08, 2011
WO 407939	SP 1293 Annual Inspection of Flood Control Measures	March 25, 2011
CAP 1260473	Technical Review Pending Internal Flooding Evaluations	April 13, 2011
CAP 1279556	Unit 1 Circulating water High Level Trip Switch – No apparent Testing	April 07, 2011
WR 66064	Hose Clamp on Flood Barrier on Sump B to 11 RHR Loose	March 26, 2011
CAP 1277847	Hose Clamp on Flood Barrier on Sump B to 11 RHR Loose	March 28, 2011
CAP 1277773	Measured Door Gaps Are Less Than Assumed in Calculation	March 28, 2011

03.04 Assess the thoroughness of the licensee's walkdowns and inspections of important equipment needed to mitigate fire and flood events to identify the potential that the equipment's function could be lost during seismic events

Number	Description or Title	Date or Revision
CAP 1280101	Evaluate INPO IER 11-1, Recommendation No. 4 with Respect to Fires	April 11, 2011
CAP 1280380	Evaluate INPO IER 11-1, Recommendation No. 4 with Respect to Flooding	April 12, 2011

LIST OF ACRONYMS USED

ADAMS	Agencywide Documents Access and Management System
CAP	Corrective Action Program
CFR	Code of Federal Regulations
EDG	Emergency Diesel Generator
ERO	Emergency Response Organization
IP	Inspection Procedure
NRC	United States Nuclear Regulatory Commission
SAMG	Severe Accident Management Guidelines
SBO	Station Blackout
SSC	Structure, System or Component
TI	Temporary Instruction

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

John B. Giessner, Chief
Branch 4
Division of Reactor Projects

Docket Nos. 50-285; 50-306; 72-010
License Nos. DPR-42: DPR-60; SNM-2506

Enclosure: Inspection Report 05000282/2011009; 05000306/2011009

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NAME	RLerch:dtp		JGiessner					
DATE	05/05/11		05/08/11					

OFFICIAL RECORD COPY

Letter to M. Schimmel from J. Giessner dated May 13, 2011.

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2 - NRC TEMPORARY INSTRUCTION 2515/183 INSPECTION REPORT 05000282/2011009; 05000306/2011009

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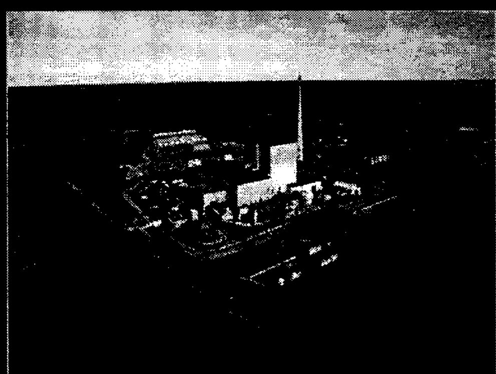
Exhibit D

Xcel Energy®
RESPONSIBLE BY NATURE™

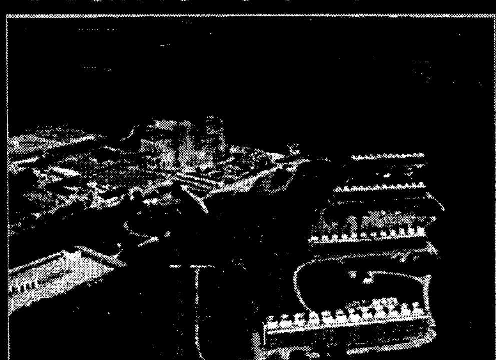
Nuclear Power
Low Cost, Reliable and Carbon Free

Monticello



- Boiling-water reactor
- One unit with about 600 MW
- Began commercial operation in 1971
- NRC renewed license for operations until 2030

Prairie Island

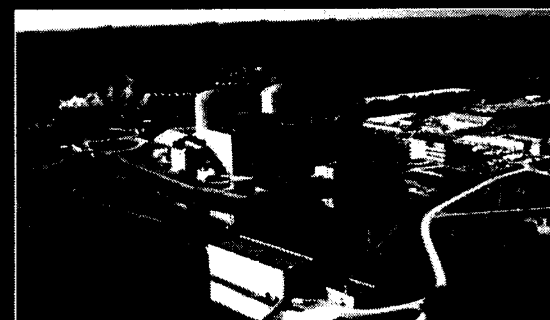


- Pressurized water reactors
- Two units with about 550 MW each
- Began commercial operation in 1973 and 1974
- License renewal is pending NRC approval; decision expected in 2011

Xcel Energy®
RESPONSIBLE BY NATURE™

Nuclear Power
Life Extension and Uprate

- Extend operating life by 20 years
- Increase output by 235 MW
- Total cost ≈ $1 billion
- Regulatory approvals underway

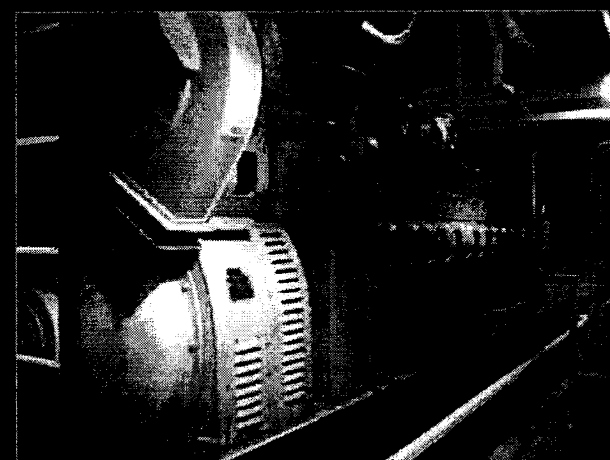


Plant	Request	Approvals		Estimated Completion
		MPUC	NRC	
Monticello	Life Extension	☑	☑	Fall 2011
	Uprate	☑	Pending	
Prairie Island	Life Extension	☑	Pending	PI Unit 1 - 2014 PI Unit 2 - 2015
	Uprate	☑	Pending	

Xcel Energy®
RESPONSIBLE BY NATURE℠

Nuclear Power
Multiple Safety Systems

- Each reactor has two diesel generators, each has enough fuel to supply all of the safety-related needs for at least a week
- If the diesel generators failed, battery backup systems would supply power
- Plants have steam-driven turbines that supply water to the reactors without electricity



- In the event of an extended station blackout, stand-alone diesel-driven pumps provide water to the reactor and spent fuel pool from the Mississippi River

Xcel Energy®
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Nuclear Power
Multiple Safety Systems

- Monticello has eight ways to get water into the core in an emergency
- Prairie Island has nine independent ways to get water into the cores in an emergency

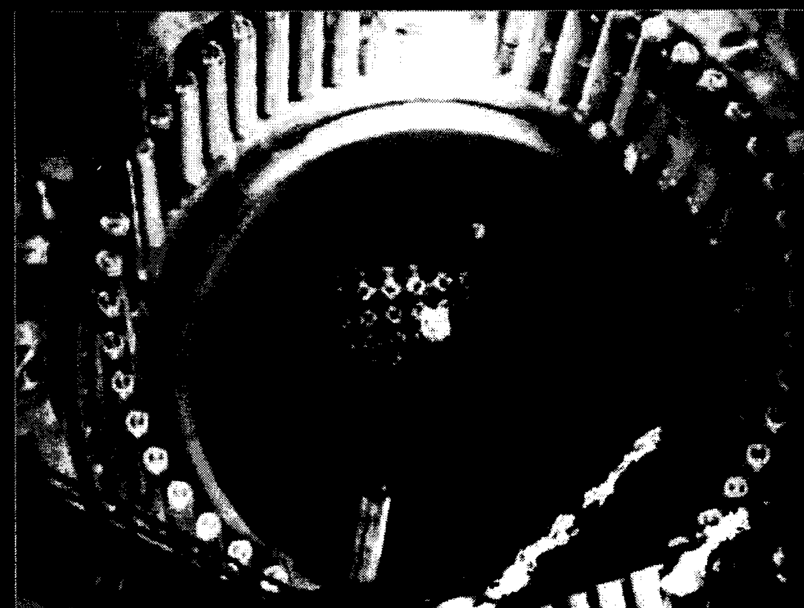

Exhibit E

XCEL ENERGY FIRST QUARTER 2011 EARNINGS
April 28, 2011, 10:00 AM ET
Chairperson: Paul Johnson (Mgmt.)

Operator: Ladies and gentlemen, thank you for standing by and welcome to the Xcel Energy First Quarter 2011 Earnings conference call. During today's presentation, all parties will be in a listen-only mode. Following the presentation, the conference will be open for questions. If you have a question, please press the star, followed by the one, on your touchtone phone. If you'd like to withdraw your question, please press the star, followed by the two. If you are using speaker equipment, please lift the handset before making your selection. This conference is being recorded today, Thursday, April 28th, 2011.

I would now like to turn the conference over to Paul Johnson, Managing Director of Investor Relations and Assistant Treasurer. Please go ahead.

Paul Johnson: Thank you and welcome to Xcel Energy's First Quarter 2011 Earnings Release conference call. With me today are Ben Fowke, President and Chief Operating Officer; Dave Sparby, Vice President and Chief Financial Officer; Teresa Madden, Vice President and Controller; Scott Wilensky, Vice President of Regulatory and Resource Planning; George Tyson, Vice President and Treasurer, and Dennis Koehl, Vice President and Chief Nuclear Officer. Today we plan to cover our first quarter results and accomplishments. In addition, we are reaffirming our annual earnings guidance of $1.65 to $1.75 per share. Please note that there are slides that accompany the conference call which are available on our web page.

I want to remind everyone that some of our comments may contain forward-looking information. Significant factors that could cause results to differ from those anticipated are described in our earnings release and our filings with the SEC.

You will notice that today's press release refers to both GAAP and ongoing earnings. First quarter 2011 ongoing earnings were $0.42 per share compared with $0.42 per share in 2010. First quarter 2011 GAAP earnings were also $0.42 per share compared with $0.36 per share in 2010. While there was no difference between GAAP and ongoing earnings in 2011, during the first quarter of 2010 ongoing earnings excluded the impact of adjustments related to the discontinued COLI program and adjustments associated with Medicare Part D subsidies. Management believes ongoing earnings provides a more meaningful comparison of earnings results and is representative of Xcel Energy's fundamental core earnings power. As a result, we will only discuss ongoing earnings during this call. Please see our earnings release for a reconciliation of GAAP to ongoing earnings.

With that, I'll now turn the call over to Ben.

Benjamin Fowke: Thank you and good morning. As Paul mentioned, we reported first quarter ongoing earnings of $0.42 per share compared with $0.42 per share in 2010. I'm pleased to report that in addition to delivering a solid quarter financially, we continued to execute on our strategy. This morning I'll focus my prepared comments on three items of current interest: our decision to terminate the Merricourt Wind Project, our preliminary take on EPA's proposed MACT rules, and the depth of our safeguards at our nuclear operations.

Earlier this month, we terminated our agreement with enXco for the development of the 150 megawatt Merricourt Wind Project in North Dakota. This was slated to be a $400 million project going into service in late 2011. We terminated the agreements because the project did not close by the contractual closing date and certain conditions required for closing were not satisfied. These conditions included a failure to resolve concerns about potential adverse consequences the project could have on two endangered species and a failure to obtain the Certificate of Site Compatibility. Given the uncertainty around the timing, cost and prospects for resolving these issues, we concluded it was in the best interest of our customers to terminate our agreements for this project based on our contractual rights. As a result of this decision, all of our investment in the project has been refunded.

We are now forecasting 2011 capital expenditures of approximately 2 billion. We've also updated our rider revenue guidance for 2011 to reflect the termination of this agreement. We remain interested in owning additional wind capacity and we are evaluating wind ownership opportunities in North Dakota.

Turning to the recently proposed EPA rules, last month the EPA issued their proposed MACT rules addressing emissions. Like many of our peers, we are in the process of evaluating what, if any, impact they may have on our operations. Based on our preliminary review, we do not anticipate that the rule will require extensive changes to our plans at NSP and PSCo. Our proactive steps to reduce emissions through the MERP project in Minnesota and our plans for the Clean Air, Clean Jobs act in Colorado put us in good position to comply with these rules. The proposed rules may have a significant impact our facilities at SPS; however, at this point we do not anticipate a material change to our five-year capex forecast.

Lastly, I'll comment on the safety of our nuclear fleet. In response to the recent events at Fukushima nuclear plants, all U.S. nuclear power plants, including our Prairie Island and Monticello plants have assessed their capabilites to maintain safety in the face of severe adverse events, including the loss of significant operational and safety systems. Nuclear power plants are built to withstand environmental hazards, including earthquakes, hurricanes, tornadoes and floods. Even plants like ours that our located outside of areas with extensive seismic activity are designed for safety in the event of such a natural disaster.

If either of our plants experienced an adverse event, our normal safety systems would keep the reactor core cool. We have two diesel generators for each unit, each one capable of supplying power to meet all the safety related needs for that unit should the plant be disconnected from the power grid. In addition, our fuel tanks are stored and sealed below ground which protects them from natural disasters. Should diesel generators fail, our facilities are equipped with battery back-up systems. In addition, we have pumps that are driven by steam turbines that do not depend on electricity. In the unlikely event that none of the normal and backup safety systems were available to keep the reactor core cool, we have portable pumps that could be hooked up to supply cooling water into the reactor from the Mississippi River.

Finally, our plants have multiple sources of getting water into the core. For example, our Monticello plant has eight independent ways to get water into the core during an emergency, while our Prairie Island plant has nine independent ways to get water into the core.

In summary, we believe the design of our plants, their geographic location, and the robust nature of our systems significantly reduce the likelihood of an emergency on the scale experienced in Japan.

That said, there are always lessons learned from a disaster. We are participating in an industry working group. The group's focus will center on understanding the events that occurred at Fukushima and recommending actions to improve the ability of U.S. plants to withstand similar events. In the meantime, we continue to work to complete the life extension at our Prairie Island plant and our plant power upgrades at both Monticello and Prairie Island. We anticipate the time frame may be delayed a bit but we don't anticipate any material changes to our plans.

I'll now turn the call over to Dave who will walk you through our first quarter results and provide a regulatory update. Dave?

David Sparby: Thanks, Ben. Now let's take a look at the details of our first quarter results, beginning with a review of each of our subsidiaries. For the quarter, earnings at PSCo decreased by $0.03 per share due to the impact of lower seasonal rates as well as higher O&M expenses, property tax, and depreciation expense. These expense increases were partially driven by capital investments made in 2010, including Comanche 3 and the natural gas plants we acquired in Colorado. At NSP Minnesota, earnings increased by $0.04 per share due to interim rate increases in Minnesota and North Dakota, as well as moderate sales growth and colder weather. The positive items were partially offset by higher O&M expenses, property tax, and depreciation expense. Earnings at NSP Wisconsin and SPS were both flat for the quarter.

Next I'll discuss the drivers that affected various lines of the income statement, beginning with retail electric margin. Our first quarter electric margin increased by $90 million, driven by two primary items: retail rate increases in Colorado, Texas and Wisconsin, along with interim rate increases in Minnesota and North Dakota, increased electric margin by $34 million. The impact of rate increases was partially offset by the impact of lower seasonal electric rates in Colorado.

Electric margin also increased by $34 million due to recovery of the revenue requirements associated with PSCo's acquisition of two natural gas facilities in late 2010. Please note that the increase in revenue requirements was partially offset by expenses such as higher O&M, depreciation, and property taxes. Increased rider, conservation and DSM revenue, as well as increased sales and weather, also contributed to the quarterly improvement in electric margin.

Natural gas margins increased $13 million in the first quarter due primarily to increased conservation and DSM revenue, which was partially offset by expenses. In addition, colder than normal weather also helped to offset a modest sales decrease.

Turning to expenses, first quarter O&M expenses increased about $29 million or about 6%. This was driven by several items, including higher employee benefit expenses related to pension, higher labor costs, as well as higher plant generation and nuclear plant generation costs. We expect that O&M expense will increase up to 4% in 2011. The quarterly increase in slightly higher than our annual guidance largely due to the timing of O&M expenses.

Depreciation and amortization expense increased about $19 million or 9%. This increase is consistent with our expectations and was driven by several plants coming online in 2010, including Comanche 3, the Nobles wind farm, and the acquisition of two natural gas plants. Finally, other taxes increased approximately $15 million or 19%, largely due to increased property tax from capital projects going into service, primarily in Minnesota and Colorado.

Next, I'll discuss our 2011 financing plans. We have updated our plans to reflect a 2011 capital expenditure forecast of approximately $2 billion. As a result, we no longer plan to issue first mortgage bonds at NSP Minnesota this year. The rest of our financing plans remain unchanged. In addition to periodic issuance and repayment of short-term debt, we plan to issue the following securities: approximately $250 million of first mortgage bonds at PSCo during the second half of 2011; SPS may issue approximately $150 million of bonds during the summer of 2011; and we anticipate issuing approximately $75 million of equity through Xcel Energy strip in various benefit programs in 2011. Naturally, our financing plans are subject to change depending on capital expenditures, internal cash generation, market conditions, and other factors.

Lastly, I'll provide an update on the rate cases that are currently underway in our various jurisdictions. In Minnesota, we have a pending electric case seeking a 2011 rate increase of $148 million based on a 2011 forecast test year, 11.25% ROE, rate base of 5.6 billion and a 52.6% equity ratio. Interim rates of 123 million, subject to refund, went into effect in January. We also requested to increase 2012 rates by an additional 48 million for known and measurable cost increases. Earlier this month, intervenors filed direct testimony. The primary intervenor, the Office of Energy Security, recommended an increase of approximately $57 million for 2011 based on a recommended ROE of 10.53% and an equity ratio of 52.6%. They also recommended an additional $34 million rate increase for 2012. While the overall recommendation was lower than anticipated, we plan to file rebuttal testimony next month in which we will provide additional support for our position and adjust our request as appropriate. We're confident that we can work through many of the more complex issues, such as income tax adjustments and pension costs, which represent a large portion of the difference. We anticipate a decision from the Minnesota commission in the fourth quarter.

In Colorado, we have a $26 million gas request pending. The request is based on a 2011 forecast test year, a 10.9% ROE, and an equity ratio of 57%. In April, intervenors filed testimony and we were disappointed by the recommendations. The staff recommended a rate decrease of $20 million based on a historical test year, a 9.375% ROE, and a hypothetical capital structure with an equity ratio of 51.8%. Next month we'll file rebuttal testimony in which we'll provide a significant amount of additional support for our position on a number of issues, including the cost of capital. Ultimately, we expect to reach a constructive outcome.

In North Dakota, we're requesting a $20 million electric rate increase. Interim rates of 17.4 million went into effect in February. Intervenor testimony is scheduled for June and rebuttal testimony in July. We anticipate a decision later in 2011.

At SPS, we filed an electric rate case in New Mexico seeking an annual base rate increase of $20 million. Notably, the rate filing is based on a 2011 test year adjusted for known and measurable changes for 2012. Rates are expected to be effective in early 2012.

In Texas, the commission approved our settlement which provided for an overall increase of $23 million in 2011 and a step-in increase of 13 million for 2012. While there is still work to be done, we continue to make progress at SPS.

Looking ahead, we're required to file an electric and gas rate case in Wisconsin early in June. We'll update you on this request during our second quarter conference call.

You may have noticed that we've adjusted some of our key guidance assumptions in our earnings release. Specifically, we reduced our rider revenue, depreciation and interest expense assumptions to reflect the cancellation of the Merricourt Project. The overall impact is a reduction in EPS of about $0.02 per share for 2011; however, we've had another solid quarter and remain on track to deliver earnings within our annual earnings guidance of $1.65 to $1.75 per share.

With that, let's open it up for questions.

Operator: Ladies and gentlemen, we will now begin the question and answer session. As a reminder, if you have a question, please press the star, followed by the one, on your touchtone phone. If you would like to withdraw your question, please press the star, followed by the two; and if you are using speaker equipment, you will need to lift the handset before making your selection.

And once again, ladies and gentlemen, star, one, for any questions.

And our first question is from the line of James Bellesa with D.A. Davidson. Please go ahead.

Michael Bates: Good morning guys. This is Michael Bates here with Jim. I just wanted to follow up on your comment, Dave, about your taxes other than income taxes. You know, it's higher this year because you've brought on new capital projects, but is the $96.6 million level that we saw in the first quarter a good kind of run rate going forward? Was there anything that you saw as irregular about that?

David Sparby: You know, property tax rates may creep up throughout the year. I mean, what we've seen is primarily attributable, of course, to property additions; but all of the counties we serve, of course, are continuously evaluating their property tax rates and it is possible that we could see some additional creep towards the end of the year.

Michael Bates: Great. Thanks, guys.

David Sparby: Thank you.

Operator: And ladies and gentlemen, if there are any additional questions, please press the star, followed by the one, on your touchtone phone. If you are using speaker equipment, you will need to lift the handset before making your selection.

And I'm showing no further questions. Please continue with any closing remarks.

Benjamin Fowke: Yes, I want to thank everyone for attending the call this morning. If there is any follow-up questions, please direct them to our IR team. We thank you very much for attending.

Operator: Ladies and gentlemen, this concludes the Xcel Energy First Quarter 2011 Earnings conference call. If you'd like to listen to a replay of today's conference, please dial 303-590-3030 or 1-800-406-7325 followed by the access code of 4431007 and the pound sign. Thank you for your participation. You may now disconnect.

END

Exhibit F

Attachment 6 of L-MT-10-003

Monticello MELLLA+ Risk Assessment

MONTICELLO MELLLA+ RISK ASSESSMENT

Prepared for:
Xcel Energy

Prepared by:

ERIN Engineering and Research, Inc.
an SKF Group Company

NOVEMBER 2009
Revision 2

EXECUTIVE SUMMARY

The proposed MELLLA+ operating region for Monticello has been reviewed to determine the net impact on the Monticello risk profile.

The existing Monticello Probabilistic Risk Assessment (PRA) is based on the EPU MELLLA operating region. The enclosed assessment of the MELLLA+ impacts on risk has been performed relative to the current PRA. The guidelines from the NRC (Regulatory Guide 1.174) are followed to assess the change in risk as characterized by core damage frequency (CDF) and Large Early Release Frequency (LERF) and to determine if the change in risk is anything but very low.

The scope of this report includes assessment of the risk impacts due to internal events (including internal flooding scenarios) using as the base reference model the MNGP Level 1 and Level 2 EPU MELLLA PRA ***average maintenance*** model (fault tree ***Risk-T&M-EPU.caf***). The impact on external events risk is assessed using the analyses of the Monticello Individual Plant Examination of External Events (IPEEE) Submittal [10] and industry studies (e.g., NUREG/CR-6850). MELLLA+ has no impact on the risk associated with accidents initiated during shutdown conditions.

The best estimate of the risk increase for at-power internal events due to MELLLA+ is a delta CDF of 7.36E-8. The best estimate at-power internal events LERF increase due to MELLLA+ is a delta LERF of 1.62E-8.

Using the NRC guidelines established in Regulatory Guide 1.174 and the calculated results from the Level 1 and 2 PRA, the best estimate for the CDF risk increase (7.36E-8/yr) and the best estimate for the LERF increase (1.62E-8/yr) are both within Region III (i.e., changes that represent very small risk changes).

Based on these results, the proposed MNGP MELLLA+ operating region is acceptable on a risk basis.

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Section 1
INTRODUCTION

Monticello is currently pursuing a License Amendment Request for operation using the MELLLA+ enhanced operating region. The expanded operating range is designed to enable plants that have pursued power uprates to be operated more efficiently. The proposed changes expand operating range flexibility but do not increase the licensed power level, operating pressure or the maximum core flow.

The purpose of this report is to:

(1) Identify any significant change in risk associated with MELLLA+ as measured by the Monticello PRA models

(2) Provide the basis for the impacts on the risk model associated with MELLLA+

(3) Review the plant specific risk impacts of EPU and evaluate them at MELLLA+ conditions

1.1 BACKGROUND

The Monticello PRA is a state-of-the-technology tool developed consistent with current PRA methods and approaches. The MNGP model is developed and quantified using the CAFTA (part of the EPRI R&R Workstation) software.

The Monticello PRA is based on realistic assessments of system capability over the 24 hour mission time of the PRA analysis. Therefore, PRA success criteria may be different than the design basis assumptions used for licensing Monticello. This report examines the risk profile changes from this realistic perspective to identify changes in the risk profile on a best estimate basis that may result from postulated accidents, including severe accidents.

1.2. PRA QUALITY

The quality of the MNGP PRA models used in performing this risk assessment is manifested by the following:

- Sufficient scope and level of detail in PRA
- Active maintenance of the PRA models and inputs
- Comprehensive Critical Reviews

<u>Scope and Level of Detail</u>

The MNGP PRA is of sufficient quality and scope for this application. The MNGP PRA modeling is highly detailed, including a wide variety of initiating events (e.g., transients, internal floods, LOCAs inside and outside containment, support system failure initiators), modeled systems, extensive level of detail, operator actions, and common cause events.

<u>Maintenance of Model, Inputs, Documentation</u>

The MNGP PRA model and documentation has been updated to reflect the current plant configuration and to reflect the accumulation of additional plant operating history and component failure data. The base reference model used in this risk assessment is the MNGP Level 1 and Level 2 EPU MELLLA PRA ***average maintenance*** model (fault tree ***Risk-T&M-EPU.caf***). This model includes EPU implemented and planned plant modifications yet to be implemented (but will be implemented prior to MELLLA+ implementation), as well as other outstanding plant modifications that have been implemented or planned for implementation in the near future (refer to Reference [19] and Appendix A).

The Level 1 and Level 2 MNGP PRA analyses were originally developed and submitted to the NRC in February 1992 as the Monticello Individual Plant Examination (IPE) Submittal. The MNGP PRA submittal and the subsequent NRC approval are described in Section 14.01 of the MNGP USAR.

Critical Reviews

The Monticello internal events received a formal industry PRA Peer Review in October 1997. All of the "A" and "B" priority comments from the 1997 peer review have been addressed by MNGP and incorporated into the current MNGP PRA model as appropriate.

Three comparisons to the ASME PRA Standard have also been performed over the past five years.

Summary

In summary, it is found that the Monticello Level 1 and Level 2 PRAs provide the necessary and sufficient scope and level of detail to allow the calculation of CDF and LERF changes due to MELLLA+. Refer to Appendix A for further details regarding the quality of the MNGP PRA.

1.3 PRA DEFINITIONS AND ACRONYMS

Definitions

The following PRA terms are used in this study:

CDF – Core Damage Frequency (CDF) is a risk measure for calculating the frequency of a severe core damage event at a nuclear facility. Core damage is the end state of the Level 1 PRA. A core damage event may be defined in the MNGP PRA by one or more of the following:

- Maximum core temperature greater than 2200 degrees Fahrenheit,

- RPV water level at 1/3 core height and decreasing,
- Containment failure induced loss of injection.

CDF is calculated in units of events per year.

With respect to analyzing MAAP thermal hydraulic runs, very short spikes (e.g., seconds or a couple minutes) above 2200F are not automatically declared core damage. The case is typically re-run and re-analyzed carefully.

LERF – Large Early Release Frequency (LERF) is a risk measure for calculating the frequency of an offsite radionuclide release that is HIGH in fission product magnitude and EARLY in release timing. A HIGH magnitude release is defined as a radionuclide release of sufficient magnitude to have the potential to cause early fatalities (e.g., greater than 10% Cesium Iodide contribution to release). An EARLY timing release is defined as the time prior to that where minimal offsite protective measures have been implemented (e.g., less than 6 hours from accident initiation). LERF is calculated in units of events per year.

Initiating Event – Any event that causes/requires a scram/manual shutdown (e.g., Turbine Trip, MSIV Closure) and requires the initiation of mitigation systems to reach a safe and stable state. An initiating event is modeled in the PRA to represent the primary transient event that can lead to a core damage event given failure of adequate mitigation systems (i.e., adequate with respect to the transient in question).

Internal Events – Those initiating events caused by failures internal to the system boundaries. Examples include Turbine Trip, MSIV Closure, Loss of an AC Bus, Loss of Offsite Power, and internal floods.

External Events – Those initiating events caused by failures external to the system boundaries. Examples include fires, seismic events, and tornadoes.

HEP – Human Error Probability (HEP) is the probabilistic estimate that the operating crew fails to perform a specific action (either properly or within the necessary time frame) to support accident mitigation. The HEP is calculated using industry methodologies and considers a number of performance shaping factors such as:

- training of the operating crew,
- availability of adequate procedures,
- time required to perform action
- time available to perform action
- stress level while performing action

HRA – Human Reliability Analysis (HRA) is the systematic process used to evaluate operator actions and quantify human error probabilities.

MAAP – The Modular Accident Analysis Package (MAAP) is an industry recognized thermal hydraulic code used to evaluate design basis and beyond design basis accidents. MAAP can be used to evaluate thermal hydraulic profiles within the primary system (e.g., RPV pressure, boildown timing) prior to core damage. MAAP also can be used to evaluate post core damage phenomena such as RPV breach, containment mitigation, and offsite radionuclide release magnitude and timing.

Level 1 PRA – The Level 1 PRA is the evaluation of accident scenarios that begin with an initiating event and progress to core damage. Core damage is the end state for the Level 1 PRA. The Level 1 PRA focuses on the capability of plant systems to mitigate a core damage event.

Level 2 PRA – The Level 2 PRA is a continuation of the Level 1 PRA evaluation. The Level 2 PRA begins with the accident scenarios that have progressed to core damage and evaluates the potential for offsite radionuclide releases. Offsite radionuclide release is the end state for the Level 2 PRA. The Level 2 PRA focuses on the capability of plant systems (including containment structures) to prevent a core damage event to result in an offsite release.

RAW – The Risk Achievement Worth (RAW) is the calculated increase in a risk measure (e.g., CDF or LERF) given that a specific system, component, operator action, etc. is assumed to fail (i.e., failure probability of 1.0). RAW is presented as a ratio of the risk measure given the component is failed divided by the risk measure given the component is assigned its base failure probability.

FV – The Fussell-Vesely (FV) importance is a measure of the contribution of a specific system, component, operator action, etc. to the overall risk. F-V is presented as the percentage of the overall risk to which the component failure contributes. In other words, the F-V importance represents the overall decrease in risk if the component is guaranteed to successfully operate as designed (i.e., failure probability of 0.0).

Acronyms

The following acronyms are used in this study:

ABA	Amplitude Based Algorithm
AC	Alternating Current
ACRS	Advisory Committee on Reactor Safeguards
ADS	Automatic Depressurization System
AOP	Abnormal Operating Procedure
APRM	Average Power Range Monitor
ARI	Alternate Rod Insertion
ARTS	APRM / RBM Technical Specifications
ASEP	Accident Sequence Evaluation Program
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
BHEP	Base Human Error Probability
BIIT	Boron Injection Initiation Temperature
BOC	Break Outside Containment
BOP	Balance of Plant
BSP	Backup Stability Protection
BWR	Boiling Water Reactor
BWROG	Boiling Water Reactor Owners Group
CCF	Common Cause Failure
CDF	Core Damage Frequency
CHR	Containment Heat Removal
CLTP	Current Licensed Thermal Power
CRDH	Control Rod Drive Hydraulics
CS	Core Spray
CST	Condensate Storage Tank
CSW	Condensate Service Water
CTS	Condensate Transfer System
DBA	Design Basis Accident
DC	Direct Current
DFP	Diesel Driven Fire Pump
DHR	Decay Heat Removal
DSS-CD	Detect and Suppress Solution - Confirmation Density
DW	Drywell
ECCS	Emergency Core Cooling System
ED	Emergency Depressurization
EDG	Emergency Diesel Generator
EOOS	Equipment Out of Service
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
EPU	Extended Power Uprate

FB	Flow Biased
FIV	Flow Induced Vibration
FIVE	Fire-Induced Vulnerability Evaluation
FPS	Fire Protection System
FSAR	Final Safety Analysis Report
FV	Fussell-Vesely (risk importance measure)
FW	Feedwater
FWLC	Feedwater Level Control
GE	General Electric
GRA	Growth Rate Algorithm
HCTL	Heat Capacity Temperature Limit
HEP	Human Error Probability
HP	High Pressure
HPCI	High Pressure Coolant Injection
HRA	Human Reliability Analysis
HX	Heat Exchanger
I&C	Instrumentation and Control
ICF	Increased Core Flow
IORV	Inadvertently Opened Relief Valve
IPE	Individual Plant Evaluation
IPEEE	Individual Plant Evaluation of External Events
ISLOCA	Interfacing Systems LOCA
L1	Level 1 (PRA)
L2	Level 2 (PRA)
LERF	Large Early Release Frequency
LHGR	Linear Heat Generation Rate
LLOCA	Large LOCA
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LP	Low Pressure
LPCI	Low Pressure Coolant Injection
MAAP	Modular Accident Analysis Program
MCPR	Minimum Critical Power Ratio
MCR	Main Control Room
MELLLA	Maximum Extended Load Line Limit Analysis
MELLLA+	Maximum Extended Load Line Limit Analysis Plus
MFLCPR	Maximum Fraction of Limiting Critical Power Ratio
MLOCA	Medium LOCA
MNGP	Monticello Nuclear Generating Plant
MSCWLL	Minimum Steam Cooling Water Level Limit

MSIV	Main Steam Isolation Valve
MSL	Main Steam Line
MWt	Megawatt (thermal)
NEI	Nuclear Energy Institute
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
MELLLA	Maximum Extended Load Line Limit Analysis
NSSS	Nuclear Steam Supply System
NTSP	Nominal Trip Setpoint
OLMCPR	Operating Limit for Minimum Critical Power Ratio
OOS	Out Of Service
PCPL	Primary Containment Pressure Limit
PCT	Peak Clad Temperature
PRA	Probabilistic Risk Assessment (alternative term for PSA)
PSA	Probabilistic Safety Assessment (alternative term for PRA)
PSSA	Probabilistic Shutdown Safety Assessment
RAW	Risk Achievement Worth (risk importance measure)
RBCCW	Reactor Building Closed Cooling Water
RBM	Rod Block Monitor
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RHRSW	RHR Service Water
RPS	Reactor Protection System
RPT	Recirculation Pump Trip
RPV	Reactor Pressure Vessel
RWCU	Reactor Water Clean-Up
SAMG	Severe Accident Management Guidelines
SBO	Station Blackout
SDC	Shutdown Cooling
SLCS	Standby Liquid Control System
SLO	Single Loop Operation
SLOCA	Small LOCA
SMA	Seismic Margins Analysis
SORV	Stuck Open Relief Valve
SPC	Suppression Pool Cooling
SRV	Safety Relief Valve
SRVOOS	Safety Relief Valve Out of Service
SSC	Systems, Structures, and Components
STP	Simulated Thermal Power

SV	Safety Valve
TAF	Top of Active Fuel
TLO	Two Loop Operation
TRC	Time Reliability Correlation
TRM	Technical Requirements Manual
TS	Technical Specification
USAR	Updated Safety Analysis Report
VB	Vacuum Breaker
MNGP	Monticello Nuclear Generating Plant
WW	Wetwell

1.4 GENERAL ASSUMPTIONS

The MNGP MELLLA+ risk evaluation includes a limited number of general assumptions, as follows:

- This analysis is based on all the inputs provided by Xcel in support of this assessment. For systems where no hardware or procedural changes have been identified, the risk evaluation is performed assuming no impact as a result of MELLLA+.
- The plant and procedural changes identified by Xcel are assumed to reflect the as-built, as-operated plant after MELLLA+ is fully implemented.
- Replacement of components with enhanced like components does not result in any supportable significant increase in the long-term failure probability for the components.
- The PRA success criteria are different than the success criteria used for design basis accident evaluations. The PRA success criteria assume that systems that can realistically perform a mitigation function (e.g., main condenser or containment venting for decay heat removal) are credited in the PRA model. In addition, the PRA success criteria are based on the availability of a discrete number of systems or trains (e.g., number of pumps for RPV makeup).

Section 2
SCOPE

The scope of this risk assessment for the proposed MELLLA+ operating region at Monticello addresses the following plant risk contributors:

- Level 1 Internal Events At-Power (CDF)
- Level 2 Internal Events At-Power (LERF)
- External Events At-Power
  - Seismic Events
  - Internal Fires
  - Other External Events
- Shutdown Assessment

The scope of this report includes assessment of the risk impacts due to internal events (including internal flooding scenarios) using as the base reference model the MNGP Level 1 and Level 2 EPU MELLLA PRA ***average maintenance*** model (fault tree ***Risk-T&M-EPU.caf***). The Level 1 PRA risk metric used in this risk assessment is Core Damage Frequency (CDF). Level 2 PRA sequences resulting in the PRA Large-Early release category comprise the LERF risk measure used in this risk assessment

The impact on external events risk is assessed using the analyses of the Monticello Individual Plant Examination of External Events (IPEEE) Submittal [10] and industry studies (e.g., NUREG/CR-6850).

MELLLA+ has no impact on the risk associated with accidents initiated during shutdown conditions.

As discussed in Section 3, all PRA elements are reviewed to ensure that identified MELLLA+ plant changes that could affect the risk profile are addressed. The information input to this process consisted of preliminary design, procedural, and training information provided by Xcel. The final design, analytical calculations, and procedural changes had not been completed prior to this risk assessment.

Section 3
METHODOLOGY

This section of the report addresses the following:

- Analysis approach used in this risk assessment (Section 3.1)
- Identification of principal elements of the risk assessment that may be affected by MELLLA+ and associated plant changes (Section 3.2)
- Plant changes used as input to the risk evaluation process (Section 3.3)
- Scoping assessment (Section 3.4)

3.1 ANALYSIS APPROACH

The purpose of this analysis is to assess the plant-specific risk impact (relative to the EPU MELLLA risk profile) associated with MELLLA+ implementation. This analysis is performed consistent with approved guidance documents (e.g., RG 1.174 [24], NEDC-33006P [8], NEDC-32424P-A [13], NEDC-32523P-A [14], and NEDC-33004P-A [23]).

All of the seven PRA topics identified in NEDC-33004P are addressed in this analysis as they apply to the MELLLA+ risk impact. This risk assessment also considers the RAIs on the MNGP EPU LAR (References [19] and [20]) and integrates those issues as appropriate into this analysis.

In addition, Matrix 13 of the NRC Review Standard for Extended Power Uprates (RS-001) is used as the template for the approach to this MELLLA+ risk assessment.[16] Refer to Appendix B for a roadmap of the RS-001 Matrix 13 risk assessment criteria and where in this MELLLA+ risk assessment report the issues are discussed.

The approach used to examine risk profile changes is further described in the following subsections.

3.1.1 Identify PRA Elements

This task is to identify the key PRA elements to be assessed as part of this analysis for potential impacts associated with plant changes. The identification of the PRA elements uses the NEI PRA Peer Review Guidelines.[4] Section 3.2 summarizes the PRA elements assessed in this risk assessment.

3.1.2 Gather Input

The input required for this assessment is the identification of any plant hardware modifications, procedural or operational changes that are to be considered part of the proposed MELLLA+ operating region. This includes changes such as instrument setpoint changes, added equipment, and procedural modifications.

3.1.3 Scoping Evaluation

This task is to perform a scoping evaluation by reviewing the plant input against the key PRA elements. The purpose is to identify those items that require further quantitative analysis and to screen out those items that are judged to have negligible or no impact on plant risk as modeled by the MNGP PRA.

3.1.4 Qualitative Results

The result of this task is a summary which dispositions all the risk assessment elements regarding the effects of the proposed MELLLA+. The disposition consists of three Qualitative Disposition Categories:

Category A:	Potential PRA change. PRA modification desirable or necessary
Category B:	Minor perturbation, negligible impact on PRA, no PRA changes required
Category C:	No change

A short explanation providing the basis for the disposition is provided in Section 4.

3.1.5 Implement and Quantify Required PRA Changes

This task is to identify the specific PRA model changes required to reflect the MELLLA+ condition, implement them, and quantify the PRA model. Section 4.1 summarizes the review of PRA analysis impacts associated with the increased power level. These effects and other effects related to plant or procedural changes are identified and documented in Section 4.

3.2 PRA ELEMENTS ASSESSED

The PRA elements to be evaluated and assessed can be derived from a number of sources. The NEI PRA Peer Review Guidelines [4] provide a convenient division into "elements" to be examined.

Each of the major risk assessment elements is examined in this evaluation. Most of the risk assessment elements are anticipated to be unaffected by MELLLA+. The risk assessment elements addressed in this evaluation for impact due to MELLLA+ (refer to Section 4 for impact evaluation) include the following:

- Initiating Events
- Systemic/Functional Success Criteria, e.g.:
  - RPV Inventory Makeup
  - Heat Load to the Suppression Pool
  - Time to Boildown

- Blowdown Loads
- RPV Overpressure Margin
- SRV Actuations
- SRV Capacity for ATWS

- Accident Sequence Modeling
- System Modeling
- Failure Data
- Human Reliability Analysis
- Structural Evaluations
- Quantification
- Containment Response (Level 2)

3.3 INPUTS (PLANT CHANGES)

This section summarizes the plant changes due to MELLLA+. The plant changes are summarized in Table 3-1 and are discussed below.

3.3.1 Hardware Modifications

There are no hardware modifications for MELLLA+ of any importance to the PRA. None of the systems credited in the MNGP PRA require any hardware modifications for MELLLA+.

Thermal-Hydraulic Stability Detection Modifications

The MELLLA+ reactor operating domain requires an update to the plant software configuration, including the process computer and applicable operating procedures.

Core instabilities may occur in a BWR when the reactor is operated at a relatively high power-to-flow ratio and recirculation flow is reduced (e.g., trip of a recirculation pump or both recirculation pumps). Core instabilities are manifested by oscillations in reactor power. As long as the oscillations remain small, they tend to repeat on approximately a two second period. Under some conditions large power oscillations may grow and develop into random power pulses.

In addition to administrative controls to scram the plant if an exclusion zone of reactor operation is entered, MNGP employs OPRMs (Oscillation Power Range Monitors) and the DSS-CD (Detect and Suppress Solution - Confirmation Density) algorithm to automatically detect the inception of power oscillations and generate a power suppression trip signal prior to significant oscillation amplitude growth. For the current MELLLA condition the PBDA (Period Detection Based Algorithm) algorithm is the licensing basis for tripping the plant in response to thermal-hydraulic stability issues (ABA, Amplitude Based Algorithm, and GRA, Growth Rate Algorithm are the backup, defense-in-depth, stability detection algorithms). The CDA (Confirmation Density Algorithm) algorithm is also employed at MNGP but is currently not connected to RPS. As part of MELLLA+, MNGP will employ the CDA algorithm as the primary detection function for a stability event instead of the PBDA (Period Detection Based Algorithm) algorithm. The CDA algorithm is designed to result in a faster trip, if necessary, than PBDA. The PBDA function and associated setpoints will be maintained for defense-in-depth (in addition to ABA and GRA).

With the MELLLA+ condition, trip of a single recirculation pump could result in an automatic plant trip depending upon the operational conditions of the plant at the time of the pump trip. Operation at the MELLLA+ condition can be postulated to increase the frequency of a plant trip given the potential for operation at higher power-to-flow ratios at the time of a recirculation pump trip; however, the CDA trip is anticipatory in design and faster in response than PBDA such that the margin to MCPR (Minimum Critical Power Ratio) actually increases for MELLLA+ versus MELLLA. Any such initiator frequency change would be speculative. No direct or significant impact on plant transient frequencies is indicated; however, a quantitative sensitivity case is investigated in this study to determine the impact on the risk impact results if the frequency of transient initiators is conservatively postulated to increase due to the proposed changes.

Power oscillations during ATWS accidents have been analyzed generically in Reference [8]. Boron injection and water level control strategies effectively mitigate an ATWS instability event. Based on Reference [8], MELLLA+ does not increase the probability of violating ATWS acceptance criteria. The MNGP plant-specific ATWS instability calculation (TR T0202) confirmed the conclusions of Reference [8].

3.3.2 Procedural Changes

No changes to the MNGP EOPs/SAMGs or Abnormal Operating Procedures are required for MELLLA+.

Changes will be needed for all associated plant procedures, training documents, the process computer, Main Control Room (MCR) displays, and MCR Simulator related to the APRM setpoint changes discussed below.

Table 3-1

SUMMARY OF MELLLA+ PLANT CHANGES AND ASSOCIATED POTENTIAL IMPACT ON PRA

MELLLA+ Task Report	Task Report Title	Impacts PRA	Discussion
T0100	Reactor Heat Balance	No	The reactor heat balances developed in this task has no direct effect on the Monticello plant configuration or design operating margin. MELLLA+ does not change the reactor thermal power, operating pressure, steam flow, or feedwater flow. No impact on PRA due to this MELLLA+ Task Report scope and results.
T0200	Reactor Core and Fuel Performance	No	No fuel product line design changes or fuel design limit changes are necessary as a consequence of MELLLA+. Also, there is no change to the average power density as a result of MELLLA+. Final OLMCPR values greater than identified will result in MFLCPR margins less than design margins used. Various EOOS (equipment out of service) options that significantly increase the OLMCPR would likely necessitate fuel and core design changes to maintain desired MCPR margin requirements. Such issues have no direct impact on the PRA models or assumptions. No impact on PRA due to this MELLLA+ Task Report scope and results.
T0201	Power/Flow Map	No[1]	The power/flow map is used as input to subsequent MELLLA+ safety analysis tasks. Any direct effect on other Systems, Structures or Components (SSC) and design features are discussed separately in other Task Reports. No NRC approved computer codes are needed to develop the MELLLA+ reactor operating domain power/flow map. The MELLLA+ reactor operating domain requires an update to the plant software configuration, including the process computer and applicable operating procedures. Such issues have no direct impact on the PRA models or assumptions. One may postulate an increase in the frequency of transient initiators due to changes in the plant software and break-in of the software. A quantitative sensitivity case is investigated in this study to determine the impact on the risk impact results.

Table 3-1

SUMMARY OF MELLLA+ PLANT CHANGES AND ASSOCIATED POTENTIAL IMPACT ON PRA

MELLLA+ Task Report	Task Report Title	Impacts PRA	Discussion
T0202	Thermal-Hydraulic Stability	No[1]	The result of this evaluation confirms that MELLLA+ has no direct impact on MNGP design operating margin. Backup stability protection (BSP) region boundaries will be provided on a cycle-specific basis for each fuel cycle. These evaluations may show plant configuration impacts for the specific fuel cycles they are intended to cover. Single loop operation (SLO) requires implementation of certain DSS-CD setpoints different than two loop operation (TLO), which provides added protection against spurious plant trips and is administratively controlled for prompt implementation after entering SLO. As part of MELLLA+, the MNGP thermal-hydraulic stability algorithm will employ the CDA (Confirmation Density Algorithm) algorithm as the primary detection function for a stability event instead of the PBDA (Period Detection Based Algorithm) algorithm. The PBDA function and associated setpoints will be used for defense in depth. The CDA trip is anticipatory in design and faster in response than PBDA such that the margin to MCPR (Minimum Critical Power Ratio) actually increases for MELLLA+ versus MELLLA. With the MELLLA+ condition, trip of a single recirculation pump could cause an automatic plant trip depending upon the operational conditions of the plant. No direct or significant impact on plant transient frequencies is indicated; however, a quantitative sensitivity case is investigated in this study to determine the impact on the risk impact results if the frequency of transient initiators is conservatively postulated to increase due to the proposed changes. Power oscillations during ATWS accidents have been analyzed generically in Reference [8]. Boron injection and water level control strategies effectively mitigate an ATWS instability event. Based on Reference [8], MELLLA+ does not increase the probability of violating ATWS acceptance criteria. The MNGP plant-specific ATWS instability calculation (TR T0202) confirmed the conclusions of Reference [8].

Table 3-1

SUMMARY OF MELLLA+ PLANT CHANGES AND ASSOCIATED POTENTIAL IMPACT ON PRA

MELLLA+ Task Report	Task Report Title	Impacts PRA	Discussion
T0304	Reactor Internal Pressure Differences & Fuel Lift Evaluation	No	There is no direct impact on plant configuration or impact on design operating margins. MELLLA+ implementation will have no impact on operation in the increased core flow (ICF) portion or MELLLA region of the power-flow map. SRV OOS has no impact on Acoustic and Flow induced loads as the key parameter of sub-cooling conditions for the loads remains unchanged. ARTS has no impact on reactor internal pressure differences. Single loop operation is not allowed in the MELLLA+ region of the power-flow map. MELLLA+ operation will therefore not impact the basis for single loop operation. No impact on PRA due to this MELLLA+ Task Report scope and results.
T0306	Steam Dryer/Separator Performance	No	There is no direct impact on plant configuration or impact on design operating margins. The moisture content of steam leaving the RPV is not expected to exceed the current performance evaluation value of (< 0.5 wt%) and the carry under of the water leaving the separators may change slightly. Such issues have no direct impact on the PRA models or assumptions. No impact on PRA due to this MELLLA+ Task Report scope and results.
T0313	RPV Flux Evaluation	No	There is no direct impact on plant configuration or impact on design operating margins. Flux calculation results are used in other Task Report calculations. Such issues have no direct impact on the PRA models or assumptions. No impact on PRA due to this MELLLA+ Task Report scope and results.

Table 3-1

SUMMARY OF MELLLA+ PLANT CHANGES AND ASSOCIATED POTENTIAL IMPACT ON PRA

MELLLA+ Task Report	Task Report Title	Impacts PRA	Discussion
T0400	Containment System Response	No	There is no direct impact on plant configuration or impact on design operating margins. MELLLA+ does not involve changes to the containment structure and does not involve changes to the reactor thermal power or operating pressure. Because the sensible and decay heat do not change in the MELLLA+ operating domain, the long-term peak suppression pool temperature response does not change. Because the SRV setpoints and sensible and decay heat do not change in the MELLLA+ operating domain, the SRV loads do not change. In the Short Term Containment Analysis and Dynamic Load Analysis, the currently licensed options (MELLL, ICF (105%), and SRVOOS) are not significantly affected by MELLLA+. No impact on PRA due to this MELLLA+ Task Report scope and results.

Table 3-1

SUMMARY OF MELLLA+ PLANT CHANGES AND ASSOCIATED POTENTIAL IMPACT ON PRA

MELLLA+ Task Report	Task Report Title	Impacts PRA	Discussion
T0401	Sub-Compartment (Annulus) Pressurization Loads	No	The annulus pressurization under MELLLA+ conditions by failure of a nozzle or safe end is calculated to be 41.7 psi which is less than the design of 58 psid, therefore MELLLA+ does not affect the design of the RPV support pedestal and ring truss connections. At the bounding minimum recirculation pump speed operating point the annulus pressurization is calculated to be 42.3 psi which is less than the design of 58 psid. The shield bricks around the reactor recirculation inlet and outlet piping have been replaced with shield doors to allow easier access for inspection of the pipe welds that are located within the biological shield wall opening. At MELLLA+ conditions there is a 12.3 psi margin in the design of the Recirculation Piping Penetration Biological Shield Wall Steel Doors during postulated nozzle or safe end failure event. The potential for missiles has been eliminated by removing all of the shield bricks from the bioshield wall penetrations. No impact on PRA due to this MELLLA+ Task Report scope and results.

Table 3-1

SUMMARY OF MELLLA+ PLANT CHANGES AND ASSOCIATED POTENTIAL IMPACT ON PRA

MELLLA+ Task Report	Task Report Title	Impacts PRA	Discussion
T0407	ECCS-LOCA SAFER/GESTR	No	All 10CFR50.46 acceptance criteria for the application of the GE14 fuel in the MELLLA+ region are met. The LHGR set-down has been increased to 12.3% in the MELLLA+ region so that the peak clad temperature (PCT) results are bounded by the limiting EPU PCT result. The CLTP at MELLLA core flow condition is preserved as the basis for Licensing Basis PCT, thus, preserving a comparable measure of margin to the 2200°F Acceptance Criterion limit throughout the expanded operating domain. The Licensing Basis PCT, established by the EPU evaluation at CLTP power / MELLLA flow, is unaffected by MELLLA+ and it remains 2140°F for GE14 fuel. Recirculation drive flow mismatch limits remain acceptable in the MELLLA+ domain. The ECCS-LOCA analysis has demonstrated that temporary plant operation with three SRV OOS remains acceptable at MELLLA+ conditions. No impact on PRA due to this MELLLA+ Task Report scope and results.

Table 3-1

SUMMARY OF MELLLA+ PLANT CHANGES AND ASSOCIATED POTENTIAL IMPACT ON PRA

MELLLA+ Task Report	Task Report Title	Impacts PRA	Discussion
T0506	TS Instrument Setpoints	No(1)	The CDA algorithm will replace PBDA as the primary detection function for a stability event (the PBDA function and associated setpoints will be used for defense in depth); refer to earlier discussion in this table for Task Report T0202. The APRM Flow Biased (FB) Simulated Thermal Power (STP) High Scram at high Recirc flow rate setpoint has a new nominal trip setpoint (NTSP) for MELLLA+ conditions. The APRM FB STP Rod Block at high Recirc flow rate setpoint has a new NTSP for MELLLA+ conditions. The instrumentation for the above changed setpoint functions needs to be recalibrated for revised NTSPs. Changes will be needed for all associated plant procedures, training documents, the process computer, Main Control Room (MCR) displays, and MCR Simulator. These changes remain within design limits. No reduction in design operating margins occurs due to these changes. Operation at MELLLA+ conditions does not require changes to the TS RBM trip or enable setpoints. Operation at MELLLA+ conditions requires changes to the TLO APRM flow biased rod block and scram TS and TRM setpoints. The changes to the flow biased TLO scram line is maintained with approximately the same margin between the MELLLA+ operating region and the APRM trip as exists for MELLLA. One may postulate an increase in the frequency of transient initiators due to changes in setpoints and software. A quantitative sensitivity case is investigated in this study to determine the impact on the risk impact results.

Table 3-1

SUMMARY OF MELLLA+ PLANT CHANGES AND ASSOCIATED POTENTIAL IMPACT ON PRA

MELLLA+ Task Report	Task Report Title	Impacts PRA	Discussion
T0609	Standby Liquid Control System	No	MELLLA+ does not impose changes to the SLC system or success criteria: • Minimum weight of neutron absorber required for injection for reactor cold shutdown remains unchanged. • Minimum solution volume/concentration required for Injection remains unchanged • Minimum required boron injection rate requirements remains unchanged • Minimum allowable flow rate requirements for the SLCS pump remains unchanged • Instrumentation and setpoints remain unchanged • Design flow rate, BHP and NPSH requirements for the SLCS pump remain unchanged No impact on PRA due to this MELLLA+ Task Report scope and results.
T0900	Transient Analysis	No	There is no direct impact on plant configuration or impact on design operating margins. MELLLA+ has no impact on the ASME overpressure relief required. MELLLA+ has non-significant impact on other transient analysis results. No success criteria or scenario timings are impacted by MELLLA+. No impact on PRA due to this MELLLA+ Task Report scope and results.

Table 3-1

SUMMARY OF MELLLA+ PLANT CHANGES AND ASSOCIATED POTENTIAL IMPACT ON PRA

MELLLA+ Task Report	Task Report Title	Impacts PRA	Discussion
T0902	Anticipated Transients Without Scram	Yes	There is no direct impact on plant configuration; however, using the licensing basis code ODYN, in order to achieve RPV peak pressure results below the ASME Service Level C limit of 1500 psig, no SRV OOS is allowed at MELLLA+, compared to 1 SRV OOS for MELLLA. The more realistic TRACG calculations show that 1 SRV OOS is acceptable for the MELLLA+ condition. The base case quantification in the risk assessment assumes that 0 SRVs OOS are allowed (consistent with the licensing basis code ODYN) for an ATWS scenario. Review of the MELLLA and MELLLA+ ATWS Task Reports shows that the assessed ATWS power is approximately 10% higher for the MELLLA+ condition (until SLC is injected as the alternate reactivity control). This potential increase in ATWS power does not impact the injection systems credited for initial level/power control in the PRA. The only impacts for the PRA modeling are shorter operator action times for ATWS level/power control in the PRA and potential increased SRV cycling. Power oscillations during ATWS accidents have been analyzed generically in Reference [8]. Boron injection and water level control strategies effectively mitigate an ATWS instability event. Based on Reference [8], MELLLA+ does not increase the probability of violating ATWS acceptance criteria. The MNGP plant-specific ATWS instability calculation (TR T0202) confirmed the conclusions of Reference [8]. Failure to inject SLC and to control water level are already included in the MNGP PRA as failures that lead to core damage during an ATWS scenario.

Notes to Table 3-1:

(1) No direct impact on PRA is expected or identified. However, a quantitative sensitivity case is performed to address sensitivity of results to postulated change in transient initiating event frequency due to a break-in period associated with changes in software and setpoints.

3.3.3 Setpoint Changes

Operation at MELLLA+ conditions requires changes to the two loop operation (TLO) APRM flow biased rod block and scram TS and TRM setpoints. The changes to the flow biased TLO scram line is maintained with approximately the same margin between the MELLLA+ operating region and the APRM trip as exists for MELLLA.

The APRM Flow Biased (FB) Simulated Thermal Power (STP) High Scram at high Recirc flow rate setpoint has a new nominal trip setpoint (NTSP) for MELLLA+ conditions.

The APRM FB STP Rod Block at high Recirc flow rate setpoint has a new NTSP for MELLLA+ conditions.

The instrumentation for the above changed setpoint functions needs to be recalibrated for revised NTSPs. Changes will be needed for all associated plant procedures, training documents, the process computer, Main Control Room (MCR) displays, and MCR Simulator.

These changes remain within design limits. No reduction in design operating margins occurs due to these changes.

3.3.4 Plant Operating Conditions

MELLLA+ does not change the reactor thermal power, operating pressure, steam flow, or feedwater flow.

MELLLA+ also does not change the operating conditions of systems modeled in the PRA.

3.4 SCOPING EVALUATION

The scoping evaluation examines the hardware, procedural, setpoint, and operating condition changes to identify the potential PRA impacts that need to be considered in this risk assessment. The scoping evaluation conclusions reached are discussed in the following subsections.

3.4.1 <u>Hardware Changes</u>

The hardware and software changes required to support MELLLA+ (see Section 3.3.1) were reviewed and determined not to result in new accident types or increased frequency of challenges to plant response. There are no hardware changes of note to the plant (physical changes to the plant are limited to MCR displays and plant computer changes).

No changes to system or component response times other than the faster response time for an instability trip due to use of CDA as the primary detection algorithm (refer to Section 3.3.1). This response time change has no impact on initiating event frequencies or PRA accident mitigation modeling.

No change to the PRA in this risk assessment is necessary related to hardware and software changes. Such modifications are adjustments to maintain plant reliable operation and margins. Although equipment reliability as reflected in failure rates can be theoretically postulated to behave as a "bathtub" curve (i.e., the beginning and end of life phases being associated with higher failure rates than the steady-state period), no significant impact on the long-term average of initiating event frequencies, or equipment reliability during the 24 hr. PRA mission time due to the replacement/modification of plant components is anticipated, nor is such a quantification supportable at this time. If any degradation were to occur as a result of MELLLA+ implementation, existing plant monitoring programs would address any such issues.

No direct or significant impact on plant transient frequencies is indicated; however, a quantitative sensitivity case is investigated in this study to determine the impact on the risk impact results if the frequency of transient initiators is conservatively postulated to increase due to the proposed changes.

3.4.2 Procedure Changes

The procedure changes related to MELLLA+ were reviewed (see Section 3.3.2) and all such changes have no direct impact on the PRA (no changes to EOPs/SAMGs or Abnormal Operating Procedures). No change to the PRA in this risk assessment is necessary related to procedure changes.

3.4.3 Setpoint Changes

Setpoint changes for MELLLA+ have no direct impact on the PRA. These changes remain within design limits. No reduction in design operating margins occurs due to these changes.

No direct or significant impact on plant transient frequencies is indicated; however, a quantitative sensitivity case is investigated in this study to determine the impact on the risk impact results if the frequency of transient initiators is conservatively postulated to increase due to the proposed changes.

3.4.4 Normal Plant Operational Changes

No plant configuration or operational changes are required for MELLLA+ that would have any direct impact on the PRA. No change to the PRA in this risk assessment is necessary related to procedure changes.

No direct or significant impact on plant transient frequencies is indicated; however, a quantitative sensitivity case is investigated in this study to determine the impact on the risk impact results if the frequency of transient initiators is conservatively postulated to increase due to the proposed changes (refer to Sections 3.3.1 and 5.7-1).

Section 4.
PRA CHANGES RELATED TO MELLLA+

Section 3 has examined the plant changes (hardware, procedural, setpoint, and operational) that are part of MELLLA+. Section 4 examines these changes to identify MNGP PRA modeling changes necessary to quantify the risk impact of MELLLA+. This section discusses the following:

- Individual PRA elements potentially affected (Section 4.1)
- Level 1 PRA (Section 4.2)
- Internal Fires Induced Risk (Section 4.3)
- Seismic Risk (Section 4.4)
- Other External Hazards Risk (Section 4.5)
- Shutdown Risk (Section 4.6)
- Radionuclide Release - Level 2 PRA (Section 4.7)

4.1 PRA ELEMENTS POTENTIALLY AFFECTED BY MELLLA+

A review of the PRA elements has been performed to identify potential effects associated with MELLLA+. The result of this task is a summary which dispositions all PRA elements regarding the effects of MELLLA+. The disposition consists of three Qualitative Disposition Categories.

Category A: Potential PRA change, PRA modification desirable or necessary

Category B: Minor perturbation, negligible impact on PRA, no PRA changes required

Category C: No change

Table 4.1-1 summarizes the results from this review. Based on Table 4.1-1, only a small number of the PRA elements are found to be potentially influenced by MELLLA+.

The following PRA elements are discussed in Table 4.1-1 to summarize whether they may be affected by MELLLA+.

- Initiating Events
- Systemic/Functional Success Criteria, e.g.:
  - RPV Inventory Makeup
  - Heat Load to the Suppression Pool
  - Time to Boildown
  - Blowdown Loads
  - RPV Overpressure Margin
  - SRV Actuations
  - SRV Capacity for ATWS
- Accident Sequence Modeling
- System Modeling
- Failure Data
- Human Reliability Analysis
- Structural Evaluations
- Quantification
- Containment Response (Level 2)

4.1.1 Initiating Events

The evaluation has examined whether there may be increases in the frequency of the initiating events or whether there may be new types of initiating events introduced into the risk profile.

The MNGP PRA program encompasses an effectively exhaustive list of hazards and accident types (i.e., from simple non-isolation transients, e.g., Turbine Trip w/Bypass, to ATWS scenarios to internal fires to hurricanes to toxic releases to draindown events during refueling activities, and numerous others). Extensive and unique changes to the plant would have to be implemented to result in new previously unidentified accidents; this is not the case for MELLLA+.

The MNGP PRA initiating events can be categorized into the following:

- Internal Event Initiators
  - Transients
  - LOOP
  - LOCAs
  - Support System Failures
- Internal Floods
- External Events

<u>Internal Events</u>

The plant and procedural changes for MELLLA+ core operating range expansion does not result in any new transient initiators, nor is there anticipated any direct significant impact on internal event initiator frequencies due to MELLLA+.

Setpoint changes are established to maintain margin and operational flexibility. The minor setpoint changes are not expected to result in a direct or significant impact on internal events initiating event frequencies.

The applicability of generic and plant specific data used to derive initiating event frequencies remains applicable for the MNGP MELLLA+ risk assessment. The modifications and plant configuration changes for MELLLA+ do not warrant any changes to the MNGP PRA initiating event frequencies. The MNGP MELLLA+ implementation is not expected to have a material effect on component or system reliability as equipment operating limits, conditions, and/or ratings are not exceeded. New trains of equipment are not being added or removed. Support system dependencies are not being altered. MNGP will continue to evaluate equipment degradation and reliability using existing plant monitoring programs. Consequently, no significant impact on the long-term average of initiating event frequencies is anticipated.

With the MELLLA+ condition, trip of a single recirculation pump could result in an automatic plant trip depending upon the operational conditions of the plant at the time of the pump trip. Operation at the MELLLA+ condition may be postulated to increase the frequency of a plant trip given the potential for operation at higher power-to-flow ratios at the time of a recirculation pump trip; however, the CDA trip is anticipatory in design and faster in response than PBDA such that the margin to MCPR (Minimum Critical Power Ratio) actually increases for MELLLA+ versus MELLLA. Any such initiator frequency change would be speculative. No direct or significant impact on plant transient frequencies is indicated; however, a quantitative sensitivity case is investigated in this study to determine the impact on the risk impact results if the frequency of transient initiators is conservatively postulated to increase due to the proposed changes.

No changes to RCS piping inspection scopes or frequencies are being made for MELLLA+. In addition, MELLLA+ does not involve any changes to the RPV operating temperature and pressure or to feedwater flow. As such, no impacts on LOCA frequencies can be postulated.

The MELLLA+ operating range expansion has no impact on the probability of scram failure.

<u>Internal Flood Initiators</u>

No changes to pipe inspection scopes or frequencies are being made for MELLLA+. In addition, MELLLA+ does not involve any changes to the flow characteristics or piping boundaries of any fluid bearing system in the plant. As such, no impacts on internal flooding initiator frequencies due to MELLLA+ are postulated.

External Event Initiators

The frequencies of external event initiators (e.g., seismic events, extreme winds, fires) are not linked to reactor power/operation issues; as such, no impact on external event initiator frequencies due to MELLLA+ can be postulated.

4.1.2 Success Criteria

The success criteria for the Monticello PRA are based on realistic evaluations of system capability over the 24 hour mission time of the PRA analysis. These success criteria therefore may be different than the design basis assumptions used for licensing Monticello. This report examines the risk profile changes caused by MELLLA+ from a realistic perspective to identify changes in the risk profile that may result from severe accidents on a best estimate basis. The following subsections discuss different aspects of the success criteria as used in the PRA. MELLLA+ task reports were also used to assist in assessing impacts on success criteria.

4.1.2.1 Timing

The MELLLA+ operating region is postulated to result in higher potential ATWS power, thus reducing operator action timings during ATWS scenarios. The reduction in timings can impact the human error probability calculations. See HRA discussion in Section 4.1.6.

4.1.2.2 RPV Inventory Makeup Requirements

The PRA success criteria for RPV makeup remains the same for MELLLA+ as for the MELLLA condition.

The plant changes for MELLLA+ do not involve changes to injection systems and does not change the rated reactor power level or operating pressure. As such, the injection system success criteria for non-ATWS scenarios are unchanged for MELLLA+.

The MELLLA+ operating region is postulated to result in higher potential ATWS power, thus reducing operator action timings. Review of the MELLLA and MELLLA+ ATWS Task Reports shows that the assessed ATWS power is approximately 10% higher for the MELLLA+ condition (until SLC is injected as the alternate reactivity control). This increase in potential ATWS power does not impact the injection systems credited for initial level/power control in the PRA. The only impact relates to shorter operator action times for ATWS level/power control in the PRA. See HRA discussion in Section 4.1.6.

4.1.2.3 Heat Load to the Pool

The plant changes for MELLLA+ do not involve changes to containment heat removal systems and does not change the rated reactor power level. As such, the heat load to the suppression pool and the containment heat removal success criteria for non-ATWS scenarios are unchanged for MELLLA+.

The MELLLA+ operating region is postulated to result in higher potential ATWS power (10% higher for the MELLLA+ condition until SLC injection is completed, as discussed previously). The PRA models containment heat removal for mitigated ATWS scenarios (i.e., ATWS scenarios without level/power control are modeled as leading directly to containment failure and core damage; thus, RHR is not applicable to unmitigated ATWS scenarios). The MELLLA+ condition has no impact on the success criteria for containment heat removal options for mitigated ATWS scenarios given that the long-term containment response is non-significantly affected by MELLLA+. The only impact relates to shorter operator action times for initiation of RHR SPC. See HRA discussion in Section 4.1.6.

4.1.2.4 Blowdown Loads

The containment analyses for LOCA under MELLLA+ conditions indicate that dynamic loads on containment remain acceptable.

4.1.2.5 RPV Overpressure Margin

The RPV dome operating pressure will not be increased as a result of MELLLA+; however, the MELLLA+ operating region is postulated to result in higher potential ATWS power (approximately 10% higher for the MELLLA+ condition until SLC injection is completed).

The MNGP MELLLA PRA requires two (2) SRVs to open for initial pressure control during a transient. The MELLLA+ condition has no impact on this success criterion.

The MNGP MELLLA PRA does not require any SRVs for initial RPV overpressure control for LOCA initiators. This success criterion also remains unchanged for MELLLA+.

The MNGP EPU MELLLA PRA uses a success criterion of 7 of 8 SRVs required for RPV initial overpressure protection during an isolation ATWS scenario (e.g., MSIV Closure ATWS). The license-based ODYN software calculations performed for the MELLLA+ condition require all SRVs to be functional, no SRVs can be out of service, to maintain the RPV pressure spike below the ASME Service Level C limit of 1500 psig during an isolation ATWS event; such as an MSIV Closure ATWS (refer to MELLLA+ Task Report 0902, "ATWS"). Isolation ATWS scenario (e.g., MSIV Closure ATWS) calculations performed using the TRACG software are also documented in MELLLA+ Task Report 0902. The

TRACG software calculations showed that 1 SRV can be OOS for an isolation ATWS scenario (e.g., MSIV Closure ATWS) and the RPV pressure spike remains below the ASME Service Level C limit.

4.1.2.6 SRV Actuations

Given the MELLLA+ operating region is postulated to result in higher potential ATWS power (10% higher for the MELLLA+ condition until SLC injection is completed, as discussed previously), this risk assessment reasonably assumes an associated increase in the number of SRV cycles during the ATWS response (MELLLA vs MELLLA+ condition). As such, one may postulate an increase in the probability of a stuck open relief valve during an ATWS scenario due to an increase in the number of SRV cycles (i.e., the stuck open relief valve probability is estimated as a failure rate per cycle x no. of SRV cycles).

The stuck open relief valve probability during ATWS response used in the MNGP EPU MELLLA PRA is 2.26E-2 (basic event XVR-ATWS-C). This stuck open relief valve probability may be modified using different approaches to consider the effect of a postulated increase in valve cycles. The following three approaches are considered:

1. The upper bound approach would be to increase the stuck open relief valve probability by a factor equal to the increase in potential ATWS power (i.e., a factor of 1.1). This approach assumes that the stuck open relief valve probability is linearly related to the number of SRV cycles, and that the number of cycles is linearly related to the potential ATWS power increase.

2. A less conservative approach to the upper bound approach would be to assume that the stuck open relief valve probability is linearly related to the number of SRV cycles, BUT the number of cycles is not necessarily directly related to the potential ATWS power increase. In this case, the postulated increase in SRV cycles due to MELLLA+ would be determined by thermal hydraulic calculations (e.g., ODYN or TRACG runs).

3. The lower bound approach would be to assume that the stuck open relief valve probability is dominated by the initial cycle and that subsequent cycles have a much lower failure rate. In this approach the base stuck open relief valve probability could be assumed to be insignificantly changed by a postulated increase in the number of SRV cycles.

Approach #1 is used here to modify the PRA stuck open relief valve probability. Therefore, the MNGP EPU MELLLA PRA stuck open relief valve probability given the potential ATWS power is increased 10% from 2.26E-2 to 2.49E-02.

4.1.2.7 RPV Emergency Depressurization

The PRA success criteria for RPV emergency depressurization remains the same for MELLLA+ as for the MELLLA condition.

The plant changes for MELLLA+ do not involve changes to ADS and does not change the rated reactor power level or operating pressure. As such, the RPV emergency depressurization success criteria for non-ATWS scenarios are unchanged for MELLLA+.

The MELLLA+ operating region is postulated to result in higher potential ATWS power (10% higher for the MELLLA+ condition until SLC injection is completed, as discussed previously). This increase in potential ATWS power does not impact the RPV emergency depressurization success criteria in the PRA but does impact the operator action response time (see HRA discussion in Section 4.1.6).

4.1.2.8 Success Criteria Summary

The Level 1 and Level 2 MNGP PRAs have developed success criteria for the key safety functions. Tables 4.1-2 through 10 summarize these safety functions and the minimum success criteria under the current MELLLA condition and that required under the MELLLA+ condition:

- General Transients (Table 4.1-2)
- IORV, Transient w/SORV (Table 4.1-3)
- Small LOCA (Table 4.1-4)
- Medium LOCA (Table 4.1-5)
- Large LOCA (Table 4.1-6)
- ATWS Events (Table 4.1-7)
- Internal Floods (Table 4.1-8)
- ISLOCA, Breaks Outside Containment (Table 4.1-9)
- Level 2 (Table 4.1-10)

The only Level 1 PRA success criteria impact due to MELLLA+ is:

- 8 of 8 SRVs are required for the MELLLA+ condition for RPV initial overpressure protection during an isolation ATWS scenario (7 of 8 SRVs were required for the MELLLA condition) using the license-based ODYN software. The 8/8 SRVs required success criterion change is applied in this risk assessment for the base case risk calculation (refer to Figure 4.1-1). The realistic TRACG results that show 7 of 8 SRVs are sufficient is addressed in a best estimate sensitivity calculation (refer to Section 5.7-1).

There are no changes in transient (non-ATWS) or LOCA success criteria. The only change in success criteria across the entire PRA is the ATWS RPV overpressure protection success criterion mentioned above.

No changes in success criteria have been identified with regard to the Level 2 PRA (refer to Section 4.1.9).

4.1.3 Accident Sequence Modeling

The MELLLA+ condition does not change the plant configuration and operation in a manner such that new accident sequences or changes to existing accident scenario progressions result. A slight exception is the reduction in available operator response time for ATWS scenarios and the associated impact on operator action HEPs (this aspect is addressed in the Human Reliability Analysis section).

4.1.4 System Modeling

The MNGP plant changes associated with the MELLLA+ condition do not result in the need to change any system fault trees to address changes in standby or operational configurations, or the addition of new equipment.

Changes were made to the SRV fault tree logic for the base case risk quantification to address the Level 1 PRA success criterion change for ATWS RPV overpressure protection for MELLLA+ (refer to Section 4.1.2.8). The fault tree logic was adjusted as follows:

- SRV fault tree gate X028 revised from a 2-out-of-8 "K/N" logic gate to an "OR" gate, such that failure of any single SRV to open will result in RPV overpressurization.
- SRV CCFTO (common cause failure to open) basic events removed from under SRV fault tree gate TE_OVERPAT (SRVs Fail to Prevent Overpressure during ATWS) as they are not applicable given just a single SRV failure is assumed to fail this function for the MELLLA+ condition.

4.1.5 Failure Rate Data

The MELLLA+ change will not involve changing any plant equipment in a way that will impact component failure rates used in the PRA.

Although equipment reliability as reflected in failure rates can be theoretically postulated to behave as a "bathtub" curve (i.e., the beginning and end of life phases being associated with higher failure rates than the steady-state period), no significant impact on the long-term average of initiating event frequencies, or equipment reliability during the 24 hr. PRA mission time due to the replacement/modification of plant components is anticipated, nor is such a quantification supportable at this time. If any degradation were to occur as a result of MELLLA+ implementation, existing plant monitoring programs would address any such issues.

4.1.6 Human Reliability Analysis

MELLLA+ does not institute changes in automatic safety responses. After the applicable automatic responses have occurred, post-initiator operator actions that may be required remain the same for the MELLLA and the MELLLA+ condition. No new operator actions are required as a result of MELLLA+. No significant changes are to be made to the Control Room for MELLLA+ that would impact the MNGP PRA human reliability analysis (HRA).

The Monticello risk profile, like other plants, is dependent on the operating crew actions for successful accident mitigation. The success of these actions is in turn dependent on a number of performance shaping factors. The performance shaping factor that is principally influenced by MELLLA+ is the time available within which to detect, diagnose, and perform required actions.

The MELLLA+ operating region is postulated to result in higher potential ATWS power, thus reducing operator action timings in ATWS scenarios. Review of the MELLLA and MELLLA+ ATWS Task Reports shows that the potential ATWS power is approximately 10% higher for the MELLLA+ condition (until SLC is injected as the alternate reactivity control).

Discussion of Impact on Human Error Probabilities

Table 4.1-11 summarizes the assessment of the operator actions explicitly reviewed in support of this analysis (both Level 1 and Level 2 PRA operator actions considered).

Given that MELLLA+ impacts only ATWS scenario timings, the operator actions identified here for re-assessment are actions in ATWS scenarios.

As can be seen in Table 4.1-11, the changes in timing are estimated to result in changes to some HEPs. The changes in allowable operator action timings were made here by reducing the allowable action time by 10% (reflective of the increase in potential ATWS power for the MELLLA+ condition versus MELLLA). The HEPs were then recalculated using the same human reliability analysis techniques (HRA) as used in the MNGP PRA.

Section 5 summarizes the increase in the CDF and LERF associated with these HEP changes (in addition to other model changes).

Note that these timing changes are with respect to accident sequences modeled in a realistic manner, which allow longer time frames than design basis assumptions.

4.1.7 Structural Evaluations

MELLLA+ does not involve any changes to piping systems, the RPV, or the containment structure or capability.

4.1.8 Quantification

No changes in the MNGP PRA quantification process (e.g., truncation limit, etc.) due to MELLLA+ have been identified (nor were any anticipated). Small changes in the quantification results (accident sequence frequencies) were realized as a result of HEP and modeling changes made to reflect the MELLLA+.

4.1.9 Level 2 PRA Analysis

Given the minor change in Level 1 CDF results, minor changes in the Level 2 release frequencies can be anticipated. Such changes are directly attributable to the changes in the Level 1 PRA.

The accident sequence modeling in the Level 2 PRA is not impacted by MELLLA+. No modeling or success criteria changes are required in the post core damage Level 2 sequences due to MELLLA+. The Level 2 functions are either conservatively based or are driven by accident phenomena. Refer to Table 4.1-10.

The MELLLA+ condition has no direct or significant impact on Level 2 PRA safety functions, such as containment isolation, challenges to the ultimate containment strength and ex-vessel debris cooling:

- Containment Isolation: Containment isolation is demanded early in an accident scenario before extreme containment conditions manifest. MELLLA+ has no impact on the failure probabilities of containment isolation signals or containment isolation valves.
- Quasi-Static Pressure/Temperature Loading: Primary containment integrity is challenged as the containment pressurizes and temperatures increase. Containment failure can occur in a variety of locations and due to different mechanisms (e.g., high temperature seal failure, structural failure, penetration failure, drywell head lift, etc.). MELLLA+ does not involve any changes to the containment structure or capability.
- Containment Dynamic Loading: These challenges include un-mitigated ATWS, LOCA loads and energetic phenomena post core damage (see bullet below). Un-mitigated (inadequate level/power control, SLC failure) ATWS scenarios are modeled in the PRA as leading directly to a containment failure, this is a standard PRA modeling approach and is not changed due to MELLLA+. MELLLA+ LOCA dynamic loads on the containment have been calculated to be within safety and design limits.
- Energetic Phenomena: A variety of severe challenges to the primary containment post core damage have been identified in the MNGP PRA and in industry studies and guidelines. These energetic phenomena may

manifest at the time of the onset of core damage, the time of core slump into the lower RPV head, the time of RPV melt-through, or after core debris falls to the drywell floor and migrates. These energetic phenomena include (among others): in-vessel steam explosions, hydrogen deflagration, ex-vessel steam explosions, direct containment heating, core-concrete interaction, and drywell shell melt-through. The likelihood of each of these phenomena, and the required conditions, are based on industry generic studies and are not influenced by MELLLA+. This is a standard PRA industry practice.

- <u>Debris Cooling</u>: Debris cooling requirements are based on generic industry studies. These are approximate injection flow rates to halt the progression of the core melt. The MELLLA+ condition would not impact these success criteria.

In addition, MELLLA+ has no impact on the PRA radionuclide release categorization. MELLLA+ has no impact on radionuclide release magnitude. While the timing of ATWS scenarios can see a minor impact (e.g., reduction of 10%), this postulated timing reduction has no impact on the release timing categorization of ATWS severe accidents because all ATWS releases are assigned the earliest release categorization ("Early") in the PRA.

Table 4.1-1

REVIEW OF PRA ELEMENTS FOR POTENTIAL RISK MODEL EFFECTS

PRA Element	Disposition Category	Basis
Initiating Events	B	No new initiators or increased frequencies of existing initiators are anticipated to result from MELLLA+. However, quantitative sensitivity case that increases the Turbine Trip frequency is performed.
Success Criteria	B	RPV overpressure margin (number of SRVs/SVs required) during an ATWS impacted by MELLLA+. Thus MELLLA PRA requires 7 of 8 SRVs for an isolation ATWS scenario. The MELLLA+ license-based ODYN calculations show 8 of 8 SRVs required; but the more realistic TRACG calculations show 7 of 8 is sufficient. Conservative base case quantification will assume the license-based ODYN results apply.
Accident Sequences (Structure, Progression)	C	No changes in the accident sequence structure result from MELLLA+. The ATWS accident progression is slightly modified in timing. These changes are incorporated in the Human Reliability Analysis (HRA).
System Analysis	C	No new system failure modes or significant changes due to MELLLA+.
Data	C	No change to component failure rates.
Human Reliability Analysis	A	The MELLLA+ operating region is postulated to result in higher potential ATWS power, thus reducing operator action timings. See discussion of operator actions in Section 4.1.6.

Table 4.1-1 (Continued)

REVIEW OF PRA ELEMENTS FOR POTENTIAL RISK MODEL EFFECTS

PRA Elements	Disposition Category	Basis
Structural	C	No changes in the structural analyses are identified that would adversely impact the PRA models.
Quantification	C	No changes in PRA quantification process (e.g., truncation limit, flag settings, etc.) due to MELLLA+. However, changes in the calculated CDF and LERF results occur to the other model changes.
Level 2	C	The MELLLA+ condition has no direct or significant impact on Level 2 PRA safety functions, accident sequence progression, or release categorization. However, changes in the calculated LERF result occurs to the Level 1 PRA model changes.

Notes to Table 4.1-1:

Category A: Potential PRA change, PRA modification desirable or necessary

Category B: Minor perturbation, negligible impact on PRA, no PRA changes required

Category C: No change

Table 4.1-2

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 1) INITIATING EVENT: ***GENERAL TRANSIENTS***

Safety Function	Minimum Systems Required	
	MELLLA	MELLLA+[8]
Reactivity Control	All control rods inserted (RPS electrical and mechanical success)	Same (by definition)
Primary System Pressure Control (Overpressure)	Turbine bypass[10] or 2 of 8 SRVs[9]	Same
Primary System Pressure Control (SRVs reclose)	All SVs/SRVs must reclose	Same (by definition)
High Pressure Injection	1 FW pump & 1 Cond. pump[1, 11] or HPCI[11] or RCIC[11] or CRDH[3]	Same[3,11]
RP Emergency Depressurization	1 of 8 SRVs[12] (2/8 SRVs required for FPS and CSW injection sources)	Same[12]
Low Pressure Injection	1 LPCI pump[13] or 1 Core Spray pump[13] or 1 Condensate pump[2]	Same[13]
Alternate Injection	1 CRDH pump at nominal flow for late injection[3] or RHRSW A crosstie to LPCI[4] or Condensate Service Water (CSW) Injection[4] or FPS crosstie to LPCI[4]	Same[3,4]

Table 4.1-2

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 1) INITIATING EVENT: ***GENERAL TRANSIENTS***

Safety Function	Minimum Systems Required	
	MELLLA	MELLLA+[8]
Containment Heat Removal	Main Condenser[14] or 1 RHR Hx Loop[6], [14] or Containment Venting[7], [14]	Same[14]

Notes to Table 4.1-2:

(1) One FW pump injecting, with one condensate pump providing suction, is a success for high pressure injection for a transient. FW operation in the short-term does not require hotwell make-up; but the model requires hotwell makeup for the long-term.

(2) One condensate pump injecting is a success for low pressure injection for a transient. Operation in the short-term does not require hotwell make-up; but the model requires hotwell makeup for the long-term.

(3) CRDH injection flow rate at MNGP is sufficiently large that it can be used as a the sole early injection source for non-LOCA and non-ATWS scenarios if a second CRDH pump is started in a timely manner, or the flow of a single pump is enhanced (via CRDH flow enhancement procedures) in a timely manner.

MNGP EPU MELLLA MAAP runs MNGPEPU5e – MNGPEPU5h show that "enhanced CRDH" is sufficient for high pressure makeup for transients for the MELLLA condition. Nominal CRDH flow with 2 pumps is also successful as the only injection source for a transient for the EPU as long as the second pump is started in a timely manner (refer to MNGP EPU MELLLA MAAP runs MNGPEPU5b and MNGPEPU5d); except for the case in which the RPV remains at pressure (refer to MNGP EPU MELLLA MAAP runs MNGPEPU5a and MNGPEPU5c).

Later in accident sequences, many hours into the event after other injection sources have operated for some time (and have failed for some reason); CRDH is also a success but only requires one pump at nominal flow. Refer to additional clarification in Reference [20] related to RAI #4.

The MELLLA+ configuration does not impact the RPV makeup success criteria.

(4) The fire protection system alternate alignment is via LPCI and can provide 1000 gpm to the core when the RPV is at approximately 100 psi. Two (2) SRVs are required to open to support RPV depressurization in the PRA for this alignment. Fire protection for alternate injection requires manual alignment. Any one of the following FPS pumping sources is a success: diesel fire pump, electric fire pump, screen wash fire pump, or pumper truck (longer term option).

Like FPS, Condensate Service Water RPV injection alignment also requires 2 SRVs for success in the PRA. CSW alignment also requires manual actions for alignment.

RHRSW A crosstie to LPCI provides significant flow and only requires a single SRV. Like FPS and CSW alignments, RHRSW crosstie also requires manual actions for alignment.

The MELLLA+ configuration does not impact the RPV makeup success criteria.

(5) <Not used.>

(6) 1 RHR pump, 1 RHR heat exchanger and 1 RHRSW pump are required for success.

(7) By design and EOPs, emergency containment venting is a success in the PRA for the containment heat removal function. The PRA credits the hard-pipe, wetwell, and drywell vent paths for containment heat removal.

(8) The success criteria for the MELLLA+ configuration are based on MELLLA+ Task Reports and/or engineering judgment.

(9) MNGP EPU MELLLA MAAP runs MNGPEPU1a and MNGPEPU1a_a also show that two SRVs are required for initial RPV overpressure protection during an isolation transient (e.g., MSIV Closure) for the MELLLA configuration. The MELLLA+ configuration does not impact this success criterion.

(10) By plant design the MNGP turbine bypass is sufficient for RPV overpressure protection during a transient with the condenser heat removal path available.

(11) FW/Condensate, HPCI, and RCIC, by design, have more than enough capacity to provide coolant makeup at the MELLLA and the MELLLA+ conditions for a transient initiator.

(12) MAAP run MNGPEPU1a shows that 1 SRV is sufficient for RPV Emergency Depressurization for the EPU configuration for a transient initiator.

The MELLLA+ configuration does not impact this success criterion.

(13) LPCI, Core Spray, and Condensate, by design, have more than enough capacity to provide coolant makeup for the MELLLA and MELLLA+ conditions for a transient initiator (Refer to MELLLA+ Task Report T0900, "Transient Analysis").

(14) By plant design, the main condenser, RHR system, and emergency containment vent are successful for the MELLLA condition. Also refer to EPU MELLLA MNGPEPU3 MAAP run that shows that 1 loop of SPC is effective for 24 hrs. The PRA credits RHR suppression pool cooling, shutdown cooling, and drywell spray modes. The MELLLA+ configuration does not impact this success criterion.

Table 4.1-3

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 1) INITIATING EVENT: ***IORV or TRANSIENT w/SORV***

Safety Function	Minimum Systems Required	
	MELLLA	MELLLA+[(8)]
Reactivity Control	All control rods inserted (RPS electrical and mechanical success)	Same (by definition)
Primary System Pressure Control (Overpressure)	n/a (addressed by SORV)	Same
Primary System Pressure Control (SRVs reclose)	n/a (SRV stuck-open)	Same (by definition)
High Pressure Injection	1 FW pump & 1 Cond. pump[(1), (11)] or HPCI[(11)] or CRDH[(3)]	Same[(3,11)]
RPV Emergency Depressurization	n/a (performed by SORV at t=0)[(9)]	Same
Low Pressure Injection	1 LPCI pump[(10)] or 1 Core Spray pump[(10)] or 1 Condensate pump[(2)]	Same[(10)]
Alternate Injection	1 CRDH pump at nominal flow for late injection[(3)] or RHRSW A crosstie to LPCI[(4)] or Condensate Service Water (CSW) Injection[(4)] or FPS crosstie to LPCI[(4)]	Same[(3,4)]
Containment Heat Removal	Main Condenser[(12)] or 1 RHR Hx Loop[(6), (12)] or Containment Venting[(7), (12)]	Same[(12)]

Notes to Table 4.1-3:

(1) One FW pump injecting, with one condensate pump providing suction, is a success for high pressure injection for a transient w/SORV. FW operation in the short-term does not require hotwell make-up; but the model requires hotwell makeup for the long-term.

(2) One condensate pump injecting is a success for low pressure injection for a transient w/SORV. Operation in the short-term does not require hotwell make-up; but the model requires hotwell makeup for the long-term.

(3) CRDH injection flow rate at MNGP is sufficiently large that it can be used as a the sole early injection source for non-LOCA and non-ATWS scenarios if a second CRDH pump is started in a timely manner, or the flow of a single pump is enhanced (via CRDH flow enhancement procedures) in a timely manner.

MNGP EPU MELLLA MAAP runs MNGPEPU5e – MNGPEPU5h show that "enhanced CRDH" is sufficient for high pressure makeup for transients for the MELLLA condition. Nominal CRDH flow with 2 pumps is also successful as the only injection source for a transient for the EPU as long as the second pump is started in a timely manner (refer to MNGP EPU MELLLA MAAP runs MNGPEPU5b and MNGPEPU5d); except for the case in which the RPV remains at pressure (refer to MNGP EPU MELLLA MAAP runs MNGPEPU5a and MNGPEPU5c).

Later in accident sequences, many hours into the event after other injection sources have operated for some time (and have failed for some reason); CRDH is also a success but only requires one pump at nominal flow. Refer to additional clarification in Reference [20] related to RAI #4.

The MELLLA+ configuration does not impact the RPV makeup success criteria.

(4) The fire protection system alternate alignment is via LPCI and can provide 1000 gpm to the core when the RPV is at approximately 100 psi. Two (2) SRVs are required to open to support RPV depressurization in the PRA for this alignment. Fire protection for alternate injection requires manual alignment. Any one of the following FPS pumping sources is a success: diesel fire pump, electric fire pump, screen wash fire pump, or pumper truck (longer term option).

Like FPS, Condensate Service Water RPV injection alignment also requires 2 SRVs for success in the PRA. CSW alignment also requires manual actions for alignment.

RHRSW A crosstie to LPCI provides significant flow and only requires a single SRV. Like FPS and CSW alignments, RHRSW crosstie also requires manual actions for alignment.

The MELLLA+ configuration does not impact the RPV makeup success criteria.

(5) <Not used.>

(6) 1 RHR pump, 1 RHR heat exchanger and 1 RHRSW pump are required for success.

(7) By design and EOPs, emergency containment venting is a success in the PRA for the containment heat removal function. The PRA credits the hard-pipe, wetwell, and drywell vent paths for containment heat removal.

(8) The success criteria for the MELLLA+ configuration are based on MELLLA+ Task Reports and/or engineering judgment.

(9) EPU MELLLA MAAP run MNGPEPU1a shows that 1 SRV is sufficient for RPV Emergency Depressurization for the EPU configuration for a transient initiator. The MELLLA+ configuration does not impact this success criterion

(10) LPCI, Core Spray, and Condensate, by design, have more than enough capacity to provide coolant makeup for the MELLLA and MELLLA+ conditions for a transient initiator (Refer to MELLLA+ Task Report T0900, "Transient Analysis").

(11) FW/Condensate and HPCI have more than enough capacity to provide coolant makeup at the MELLLA and the MELLLA+ conditions for a transient initiator. However, the RCIC system is not credited in the PRA for IORV/SORV scenarios because level will dip below TAF, causing the operators to initiate RPV emergency depressurization per the EOPs.

(12) By plant design, the main condenser, RHR system, and emergency containment vent are successful for the MELLLA condition. Also refer to EPU MELLLA MNGPEPU3 MAAP run that shows that 1 loop of SPC is effective for 24 hrs. The PRA credits RHR suppression pool cooling, shutdown cooling, and drywell spray modes. The MELLLA+ configuration does not impact this success criterion.

Table 4.1-4

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 1) INITIATING EVENT: ***SMALL LOCA***

Safety Function	Minimum Systems Required	
	MELLLA	MELLLA+[7]
Reactivity Control	All control rods inserted (RPS electrical and mechanical success)	Same (by definition)
Primary System Pressure Control (Overpressure)	Not required	Same
Vapor Suppression	Not required	Same
High Pressure Injection	1 FW pump & 1 Cond. pump[1], [3] or HPCI[3] [4]	Same[3,4]
RPV Emergency Depressurization	1 of 8 SRVs[9]	Same[9]
Low Pressure Injection	1 LPCI pump[6] or 1 Core Spray pump[6] or 1 Condensate pump[2], [6]	Same[6]
Alternate Injection	RHRSW A crosstie to LPCI[5] or FPS crosstie to LPCI[5]	Same[5]
Containment Heat Removal	Main Condenser[8] or 1 RHR Hx Loop[8] or Containment Venting[8]	Same[8]

Notes to Table 4.1-4:

(1) One FW pump injecting, with one condensate pump providing suction, is a success for high pressure injection for a SLOCA scenario. FW operation in the short-term does not require hotwell make-up; but the model requires hotwell makeup for the long-term.

(2) One condensate pump injecting is a success for low pressure injection for a SLOCA. Operation in the short-term does not require hotwell make-up; but the model requires hotwell makeup for the long-term.

(3) FW/Condensate and HPCI have more than enough capacity to provide coolant makeup at the EPU MELLLA condition for a SLOCA scenario. Refer to MNGP EPU MELLLA MAAP run MNGPEPU3 which shows that HPCI can function as the only injection source for a SLOCA for the EPU condition throughout the PRA 24 hour mission time. The MELLLA+ condition has no impact on this success criterion.

(4) CRDH flow is not sufficient for early or late coolant makeup for LOCA scenarios. This is true for MELLLA and MELLLA+.

(5) FPS crosstie and RHRSW crosstie are the only alternate LP systems of sufficient capacity for a SLOCA. CSW is not of sufficient capacity.

The fire protection system alternate alignment is via LPCI and can provide 1000 gpm to the core when the RPV is at approximately 100 psi. Two (2) SRVs are required to open to support RPV depressurization in the PRA for this alignment. Fire protection for alternate injection requires manual alignment. Any one of the following FPS pumping sources is a success: diesel fire pump, electric fire pump, screen wash fire pump, or pumper truck (longer term option).

RHRSW A crosstie to LPCI provides significant flow and only requires a single SRV. Like FPS, RHRSW crosstie also requires manual actions for alignment.

The MELLLA+ configuration does not impact the RPV makeup success criteria.

(6) LPCI, Core Spray, and Condensate have more than enough capacity to provide coolant makeup at the MELLLA condition for a small LOCA. Refer to MNGP EPU MELLLA MAAP run MNGPEPU4 which shows the one LPCI train is sufficient for a MLOCA. The MELLLA+ configuration does not impact the RPV makeup success criteria.

(7) The success criteria for the MELLLA+ configuration are based on MELLLA+ Task Reports and/or engineering judgment.

(8) By plant design, the main condenser, RHR system, and emergency containment vent are successful for the MELLLA condition. Also refer to EPU MELLLA MNGPEPU3 MAAP run that shows that 1 loop of SPC is effective for 24 hrs. The PRA credits RHR suppression pool cooling, shutdown cooling, and drywell spray modes. The MELLLA+ configuration does not impact this success criterion.

(9) EPU MELLLA MAAP run MNGPEPU1a shows that 1 SRV is sufficient for RPV Emergency Depressurization for the EPU configuration for a transient initiator. EPU MELLLA MAAP run MNGPEPU6a shows the 1 SRV is also sufficient for a MLOCA for RPV Emergency Depressurization. Using reasonable judgment, a SLOCA also requires only 1 SRV for RPV Emergency Depressurization. The MELLLA+ configuration does not impact this success criterion.

Table 4.1-5

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 1) INITIATING EVENT: ***MEDIUM LOCA***

Safety Function	Minimum Systems Required	
	MELLLA	MELLLA+[8]
Reactivity Control	All control rods inserted (RPS electrical and mechanical success)	Same (by definition)
Primary System Pressure Control (Overpressure)	Not required	Same
Vapor Suppression	Not required	Same
High Pressure Injection	HPCI[1] [3]	Same[1,3]
RPV Emergency Depressurization	1 of 8 SRVs[9] or HPCI initially available[2]	Same[2,9]
Low Pressure Injection	1 LPCI pump[5] or 1 Core Spray pump[5] [4]	Same[4,5]
Alternate (Late) Injection	RHRSW A crosstie to LPCI[6] or FPS crosstie to LPCI[6]	Same[6]
Containment Heat Removal	1 RHR Hx Loop[7]	Same

<u>Notes to Table 4.1-5</u>:

(1) Refer to MNGP EPU MELLLA MAAP run MNGPEPU4 which shows the HPCI is sufficient for a MLOCA for the EPU until the RPV sufficiently depressurizes so that LPCI or CS can provide low pressure RPV makeup. The MELLLA+ configuration does not impact the RPV makeup success criteria.

(2) HPCI operation in combination with the MLOCA will act as the method for RPV depressurization (refer to MNGP EPU MELLLA MAAP run MNGPEPU4). The MELLLA+ configuration does not impact the RPV makeup success criteria.

(3) FW is not credited because it assumed that the MLOCA may be in a recirculation loop, thus preventing flow from reaching the core.

(4) Condensate is not credited because it is assumed that the MLOCA will deplete the hotwell before sufficient hotwell makeup can be aligned.

(5) LPCI and Core Spray have more than enough capacity to provide coolant makeup at the MELLLA condition for a MLOCA. Refer to MNGP EPU MELLLA MAAP run MNGPEPU4 which shows the one LPCI train is sufficient for a MLOCA. The MELLLA+ configuration does not impact the RPV makeup success criteria.

(6) FPS crosstie and RHRSW crosstie are the only alternate LP systems of sufficient capacity for a MLOCA. CSW is not of sufficient capacity. FPS and RHRSW crossties are only successful for late injection (after another injection source has already operated and failed). They are not successful as the only early injection source due to lack of available time in which to complete the manual alignments.

The fire protection system alternate alignment is via LPCI and can provide 1000 gpm to the core when the RPV is at approximately 100 psi. Fire protection for alternate injection requires manual alignment. Any one of the following FPS pumping sources is a success: diesel fire pump, electric fire pump, screen wash fire pump, or pumper truck (longer term option).

Like FPS, RHRSW crosstie also requires manual actions for alignment.

The MELLLA+ configuration does not impact the RPV makeup success criteria.

(7) By plant design, the RHR system is successful for the MELLLA condition. Also refer to EPU MELLLA MNGPEPU3 MAAP run that shows that 1 loop of SPC is effective for 24 hrs. The PRA credits RHR suppression pool cooling and drywell spray modes for a MLOCA. The main condenser is not credited because the MSIVs will likely close due to accident signals. Shutdown cooling is also not credited for MLOCAs due to the potential break location in a recirculation loop. Containment venting is conservatively assumed not successful as the sole decay heat removal mechanism for MLOCAs and LLOCAs due to potential NPSH limitations on continued LPCI or CS injection. The MELLLA+ configuration does not impact this success criterion.

(8) The success criteria for the MELLLA+ configuration are based on MELLLA+ Task Reports and/or engineering judgment.

(9) EPU MELLLA MAAP run MNGPEPU6a shows the 1 SRV is also sufficient for a MLOCA for RPV Emergency Depressurization. The MELLLA+ configuration does not impact this success criterion.

Table 4.1-6

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 1) INITIATING EVENT: ***LARGE LOCA***

Safety Function	Minimum Systems Required	
	MELLLA	MELLLA+[(6)]
Reactivity Control	All control rods inserted (RPS electrical and mechanical success)	Same (by definition)
Primary System Pressure Control (Overpressure)	Not required	Same
Vapor Suppression	< 6 WW-DW vacuum breakers stuck open is acceptable[(1)]	Same[(1)]
High Pressure Injection	N/A[(2)]	Same[(2)]
RPV Emergency Depressurization	Not required	Same
Low Pressure Injection	1 LPCI pump[(3)] or 1 Core Spray pump[(3)]	Same[(3)]
Alternate Injection	RHRSW A crosstie to LPCI[(4)] or FPS crosstie to LPCI[(4)]	Same[(4)]
Containment Heat Removal	1 RHR Hx Loop[(5)]	Same

Notes to Table 4.1-6:

(1) Six (6) of eight (8) stuck open WW-DW vacuum breakers will lead to sufficient suppression pool bypass to result in containment overpressurization. This condition is assumed to lead to core damage due to loss of potential injection sources. The MELLLA+ configuration does not impact this success criterion.

(2) The LLOCA initiator results in rapid depressurization of the RPV, precluding the use of the FW, HPCI, and RCIC high pressure injection systems. In addition, the CRDH system is of inadequate flow rate to keep up with the inventory loss. The MELLLA+ configuration does not impact this success criterion.

(3) LPCI and Core Spray have more than enough capacity to provide coolant makeup at the MELLLA condition for Large LOCAs. Refer to MNGP EPU MELLLA MAAP run MNGPEPU4 which shows 1 LPCI pump is sufficient. The MELLLA+ configuration does not impact the RPV makeup success criteria.

(4) Insufficient time is available during a LLOCA to align FPS or RHRSW crossties for use as the sole early injection source. However, FPS and RHRSW crossties are credited for late injection after another injection source has operated and subsequently failed for some reason. The MELLLA+ configuration does not impact the RPV makeup success criteria.

(5) By plant design, the RHR system is successful for the MELLLA condition for containment heat removal. The PRA credits RHR suppression pool cooling and drywell spray modes for a LLOCA. The main condenser is not credited because the MSIVs will likely close due to accident signals. Shutdown cooling is also not credited for LLOCAs due to the potential break location in a recirculation loop. Containment venting is conservatively assumed not successful as the sole decay heat removal mechanism for MLOCAs and LLOCAs due to potential NPSH limitations on continued LPCI or CS injection. The MELLLA+ configuration does not impact this success criterion.

(6) The success criteria for the MELLLA+ configuration are based on MELLLA+ Task Reports and/or engineering judgment.

Table 4.1-7

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 1) INITIATING EVENT: ***ATWS***

Safety Function	Minimum Systems Required	
	MELLLA	MELLLA+[8]
Reactivity Control	ARI[1] or; 1 of 2 SLC trains[9]	Same[1,9]
Primary System Pressure Control (Overpressure)	Turbine bypass[2] or; 7 of 8 SRVs[10] and RPT[2]	Turbine bypass[2] or; 8 of 8 SRVs[11] / 7 of 8 SRVs[11] and RPT[2]
Primary System Pressure Control (SRVs reclose)	Not modeled	Same
High Pressure Injection	1 FW pump & 1 Cond. pump[3] or HPCI[3]	Same[3]
RPV Emergency Depressurization	3 of 8 SRVs[4]	Same[4]
Low Pressure Injection	1 LPCI pump[5] or 1 Core Spray pump[5]	Same[5]
Alternate Injection	N/A[6]	Same[6]
Containment Heat Removal	Main Condenser[7] or 1 RHR Hx Loop[7] or WW/DW Venting[7]	Same[7]

<u>Notes to Table 4.1-7</u>:

(1) Alternate Rod Insertion (ARI) is a successful reactivity control measure only for electrical scram failures. This success criterion remains applicable to the MELLLA+ condition.

(2) The Recirculation Pump Trip (RPT) must actuate as designed and trip both recirculation pumps for initial RPV pressure control during an isolation ATWS (e.g., MSIV Closure ATWS). If turbine bypass remains available then RPT is not needed for initial pressure control. This success criterion remains applicable to the MELLLA+ condition.

(3) By plant design and the EOPs, FW and HPCI are successful for high pressure makeup during an ATWS for the MELLLA condition (refer to MNGP EPU MELLLA+ MAAP runs MNGPEPU7b and MNGPEPU7c). This is true for the MELLLA+ condition, as well (refer to MNGP MELLLA+ Task Report 0902, "ATWS").

(4) The MNGP EPU MELLLA PRA uses 3 SRVs as the success criterion for RPV emergency depressurization during an ATWS (refer to MNGP EPU MELLLA MAAP run MNGPEPU7a). This success criterion remains applicable to the MELLLA+ configuration (refer to MNGP MELLLA+ Task Report 0902, "ATWS").

(5) By plant design and the EOPs, LPCI and Core Spray are successful for low pressure makeup during an ATWS (refer to MNGP EPU MELLLA MAAP run MNGPEPU7a). This is true for the MELLLA+ condition, as well (refer to MNGP MELLLA+ Task Report 0902, "ATWS").

(6) Alternate low pressure injection systems are not credited because it is assumed that insufficient time is available to perform the alignments during an ATWS.

(7) The main condenser, RHR system and emergency containment vent options are successful for the MELLLA condition for containment heat removal during a mitigated ATWS scenario (i.e., with successful SLC injection and level/power control), refer to MNGP EPU MELLLA MAAP run MNGPEPU7a. The MNGP EPU PRA credits the RHR suppression pool cooling mode for an ATWS. The EOPs do not direct use of SDC during an ATWS.

The MELLLA+ condition has no impact on the success criteria for containment heat removal options for mitigated ATWS scenarios given that the long-term containment response is non-significantly affected by MELLLA+. The only impact relates to shorter operator action times for initiation of RHR SPC. See HRA discussion in Section 4.1.6.

(8) The success criteria for the MELLLA+ configuration are based on MELLLA+ Task Reports and/or engineering judgment.

(9) One SLC train is sufficient for reactivity control for both the MELLLA and MELLLA+ conditions (refer to MELLLA and MELLLA+ Task Reports T0902, "ATWS").

(10) Based on EPU Task Report ATWS analysis, 7 of 8 SRVs are required for the MELLLA condition for RPV initial overpressure protection during an ATWS scenario.

(11) The license-based ODYN software calculations performed for the MELLLA+ condition require all SRVs to be functional, no SRVs can be out of service, to maintain the RPV pressure spike below the ASME Service Level C limit of 1500 psig during an isolation ATWS event, such as an MSIV Closure ATWS (refer to MELLLA+ Task Report 0902, "ATWS"). Isolation ATWS scenario (e.g., MSIV Closure ATWS) calculations performed using the TRACG software are also documented in MELLLA+ Task Report 0902. The TRACG software calculations showed that 1 SRV can be OOS for an isolation ATWS scenario (e.g., MSIV Closure ATWS) and the RPV pressure spike remains below the ASME Service Level C limit.

The 8/8 SRVs required success criterion change for isolation ATWS scenarios is applied in this risk assessment for the base case risk calculation. The realistic TRACG results that show 7 of 8 SRVs are sufficient is addressed in a best estimate sensitivity calculation (refer to Section 5.7-1).

Table 4.1-8

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 1) INITIATING EVENT: ***INTERNAL FLOODS***

Safety Function	Minimum Systems Required	
	MELLLA	MELLLA+[8]
Reactivity Control	All control rods inserted (RPS electrical and mechanical success)	Same (by definition)
Primary System Pressure Control (Overpressure)	Turbine bypass[10] or 2 of 8 SRVs[9]	Same
Primary System Pressure Control (SRVs reclose)	All SVs/SRVs must reclose	Same (by definition)
High Pressure Injection	1 FW pump & 1 Cond. pump[1, 11] or HPCI[11] or RCIC[11] or CRDH[3]	Same[3,11]
RPV Emergency Depressurization	1 of 8 SRVs[12] (2/8 SRVs required for FPS and CSW injection sources)	Same[12]
Low Pressure Injection	1 LPCI pump[13] or 1 Core Spray pump[13] or 1 Condensate pump[2]	Same[13]
Alternate Injection	1 CRDH pump at nominal flow for late injection[3] or RHRSW A crosstie to LPCI[4] or Condensate Service Water (CSW) Injection[4] or FPS crosstie to LPCI[4]	Same[3,4]

Table 4.1-8

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 1) INITIATING EVENT: ***INTERNAL FLOODS***

Safety Function	Minimum Systems Required	
	MELLLA	MELLLA+[8]
Containment Heat Removal	Main Condenser[14] or 1 RHR Hx Loop[6], [14] or Containment Venting[7], [14]	Same[14]

Notes to Table 4.1-8:

(1) One FW pump injecting, with one condensate pump providing suction, is a success for high pressure injection for a transient (which is how an internal flood scenario behaves, other than the flood impacts on mitigation equipment). FW operation in the short-term does not require hotwell make-up; but the model requires hotwell makeup for the long-term.

(2) One condensate pump injecting is a success for low pressure injection for a transient. Operation in the short-term does not require hotwell make-up; but the model requires hotwell makeup for the long-term.

(3) CRDH injection flow rate at MNGP is sufficiently large that it can be used as a the sole early injection source for non-LOCA and non-ATWS scenarios if a second CRDH pump is started in a timely manner, or the flow of a single pump is enhanced (via CRDH flow enhancement procedures) in a timely manner.

MNGP EPU MELLLA MAAP runs MNGPEPU5e – MNGPEPU5h show that "enhanced CRDH" is sufficient for high pressure makeup for transients for the MELLLA condition. Nominal CRDH flow with 2 pumps is also successful as the only injection source for a transient for the EPU as long as the second pump is started in a timely manner (refer to MNGP EPU MELLLA MAAP runs MNGPEPU5b and MNGPEPU5d); except for the case in which the RPV remains at pressure (refer to MNGP EPU MELLLA MAAP runs MNGPEPU5a and MNGPEPU5c).

Later in accident sequences, many hours into the event after other injection sources have operated for some time (and have failed for some reason); CRDH is also a success but only requires one pump at nominal flow. Refer to additional clarification in Reference [20] related to RAI #4.

The MELLLA+ configuration does not impact the RPV makeup success criteria.

(4) The fire protection system alternate alignment is via LPCI and can provide 1000 gpm to the core when the RPV is at approximately 100 psi. Two (2) SRVs are required to open to support RPV depressurization in the PRA for this alignment. Fire protection for alternate injection requires manual alignment. Any one of the following FPS pumping sources is a success: diesel fire pump, electric fire pump, screen wash fire pump, or pumper truck (longer term option).

Like FPS, Condensate Service Water RPV injection alignment also requires 2 SRVs for success in the PRA. CSW alignment also requires manual actions for alignment.

RHRSW A crosstie to LPCI provides significant flow and only requires a single SRV. Like FPS and CSW alignments, RHRSW crosstie also requires manual actions for alignment.

The MELLLA+ configuration does not impact the RPV makeup success criteria.

(5) <Not used.>

(6) 1 RHR pump, 1 RHR heat exchanger and 1 RHRSW pump are required for success.

(7) By design and EOPs, emergency containment venting is a success in the PRA for the containment heat removal function. The PRA credits the hard-pipe, wetwell, and drywell vent paths for containment heat removal.

(8) The success criteria for the MELLLA+ configuration are based on MELLLA+ Task Reports and/or engineering judgment.

(9) MNGP EPU MELLLA MAAP runs MNGPEPU1a and MNGPEPU1a_a also show that two SRVs are required for initial RPV overpressure protection during an isolation transient (e.g., MSIV Closure) for the MELLLA configuration. The MELLLA+ configuration does not impact this success criterion.

(10) By plant design the MNGP turbine bypass is sufficient for RPV overpressure protection during a transient with the condenser heat removal path available.

(11) FW/Condensate, HPCI, and RCIC, by design, have more than enough capacity to provide coolant makeup at the MELLLA and the MELLLA+ conditions for a transient initiator.

(12) MAAP run MNGPEPU1a shows that 1 SRV is sufficient for RPV Emergency Depressurization for the EPU configuration for a transient initiator.

The MELLLA+ configuration does not impact this success criterion.

(13) LPCI, Core Spray, and Condensate, by design, have more than enough capacity to provide coolant makeup for the MELLLA and MELLLA+ conditions for a transient initiator (Refer to MELLLA+ Task Report T0900, "Transient Analysis").

(14) By plant design, the main condenser, RHR system, and emergency containment vent are successful for the MELLLA condition. Also refer to EPU MELLLA MNGPEPU3 MAAP run that shows that 1 loop of SPC is effective for 24 hrs. The PRA credits RHR suppression pool cooling, shutdown cooling, and drywell spray modes. The MELLLA+ configuration does not impact this success criterion.

Table 4.1-9

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 1) INITIATING EVENT: ***ISLOCA, BOC***

Safety Function	Minimum Systems Required	
	MELLLA	MELLLA+[5]
Reactivity Control	All control rods inserted (RPS electrical and mechanical success)	Same (by definition)
Primary System Pressure Control (Overpressure)	Not required	Same
Vapor Suppression	Not required	Same
High Pressure Injection	N/A[1]	Same[1]
RPV Emergency Depressurization	Not required	Same
Low Pressure Injection	1 LPCI pump[2] or 1 Core Spray pump[2]	Same[2]
External Injection Sources	RHRSW A crosstie to LPCI[3] or Condensate Service Water (CSW) Injection[3] or FPS crosstie to LPCI[3]	Same[3]
Containment Heat Removal	N/A[4]	Same[4]

<u>Notes to Table 4.1-9</u>:

(1) Break outside containment initiators result in rapid depressurization of the RPV, precluding the use of the FW, HPCI, and RCIC high pressure injection systems. In addition, the CRDH system is of inadequate flow rate to keep up with the inventory loss.

(2) LPCI and Core Spray have more than enough capacity to provide coolant makeup at the MELLLA condition for Large LOCAs (ISLOCA and Break outside Containment scenarios are modeled as large LOCA size breaks in the PRA). Refer to MNGP EPU MELLLA MAAP run MNGPEPU4 which shows 1 LPCI pump is sufficient. The MELLLA+ configuration does not impact the RPV makeup success criteria.

(3) If a break outside containment is not isolated, reactor water inventory will continue to be discharged outside the drywell which will eventually deplete the suppression pool and disable low pressure injection via loss of suction and flooding. Consequently, external injection from a virtually unlimited supply and external pump is needed for long term core cooling. The MNGP credits FPS, RHRSW, and CWS alternate injection sources. These systems draw from the river and have a virtually infinite source of water.

The MELLLA+ configuration does not impact the RPV makeup success criteria.

(4) Decay heat removal active systems are not required for unisolated breaks outside containment, since the decay heat is carried out of containment via the break.

(5) The success criteria for the MELLLA+ configuration are based on MELLLA+ Task Reports and/or engineering judgment.

Table 4.1-10

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS: **LEVEL 2 (LERF) PRA**

Safety Functions	Minimum Systems Required	
	MELLLA	MELLLA+[3]
Containment Isolation	Containment penetrations >2" dia. isolated	Same (by definition)
RPV Depressurization post-core damage	1 of 8 SRVs (assumed same as Level 1 PRA).	Same
Arrest Core Melt Progression In-Vessel	1 LPCI pump[3] or 1 Core Spray pump[3] or 1 Condensate pump[3] or FPS crosstie[3] or RHRSW crosstie[3]	Same[3]
Combustible Gas Venting	Inerted containment with no oxygen intrusion during the accident or Combustible gas purge / vent	Same (by definition)
Containment Remains Intact at RPV Breach	Containment Isolation and No early containment failure modes (e.g., steam explosions) compromise containment integrity	Same (by definition)
Ex-vessel Debris Coolability	1 LPCI pump[3] or 1 Core Spray pump[3] or 1 Condensate pump[3] or DW Sprays[3] or FPS crosstie[3] or RHRSW crosstie[3]	Same[3]
Containment Heat Removal	1 RHR Hx Loop[1] or Containment Venting[2]	Same

Table 4.1-10

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS: **LEVEL 2 (LERF) PRA**

Safety Functions	Minimum Systems Required	
	MELLLA	MELLLA+[(3)]
Fission Product Scrubbing	No failure in DW or For WW airspace failure: no SP bypass (i.e., no WW-DW vacuum breakers stuck open and no SRV tail pipe failures)	Same (by definition)

Notes to Table 4.1-10:

(1) 1 RHR pump, 1 RHR heat exchanger and 1 RHRSW pump are required for suppression pool cooling or DW Sprays for Level 2 containment heat removal for post-core damage accidents proceeding with an initially intact containment. The MELLLA+ condition would not impact these success criteria.

(2) Containment venting is also a success for Level 2 containment heat removal for post-core damage accidents proceeding with an initially intact containment. The wetwell and drywell vents, and the hard-piped vent are credited. The MELLLA+ condition would not impact these success criteria.

(3) Debris cooling requirements are based on generic industry studies. These are approximate injection flow rates to halt the progression of the core melt. The MELLLA+ condition would not impact these success criteria.

Table 4.1-11

RE-ASSESSMENT OF OPERATOR ACTION HEPs POTENTIALLY IMPACTED BY MELLLA+

Action ID	Action Description	Allowable Action Time		MELLLA HEP	MELLLA+ HEP	Comment
		EPU MELLLA	EPU MELLLA+			
ATWS-LNG-Y	Fail to initiate ATWS when attempted	n/a	n/a	8.00E-05	8.00E-05	Execution Error: HEP calculation not directly influenced by available time window. Diagnosis contribution treated by a separate basic event.
ATWS-SHT-Y	Operator fails to initiate ATWS (short time available)	<1 min.	<1 min.	1.00E+00	1.00E+00	ASEP Upper Bound TRC curve.
CRIT-DET-Y	Fail to detect criticality issue - long time available	30 min.	30 min.	1.18E-04	1.18E-04	Diagnosis Error: This action error applies to ATWS scenarios in which the turbine is online. An indefinite, long time is available to the operator; the MELLLA PRA conservatively assumes 30 mins. available. This timing assumption is not changed by MELLLA+. ASEP Lower Bound TRC curve.
DEP-02MN-Y	Fail RPV depressurization within 2 minutes	4.4 min.	4 min.	5.10E-01	1.00E+00	This action used in isolation ATWS scenarios (e.g., MSIV Closure ATWS) with failure of all HP injection. The MELLLA PRA estimates 4.4 min. available (diagnosis time of 1.4 min. and execution time of 3 min.). The MELLLA+ risk assessment reduces the MELLLA time window for this action by an additional 10% to t=4 mins (diagnosis time of 1 min. and execution time of 3 min.). ASEP Lower Bound TRC curve.
LSBLCALTXY	Operator fails to inject boron using CRDH	n/a	n/a	6.30E-03	6.30E-03	Execution Error: HEP calculation not directly influenced by available time window. Diagnosis contribution treated by a separate basic event.

Table 4.1-11

RE-ASSESSMENT OF OPERATOR ACTION HEPs POTENTIALLY IMPACTED BY MELLLA+

Action ID	Action Description	Allowable Action Time		MELLLA HEP	MELLLA+ HEP	Comment
		EPU MELLLA	EPU MELLLA+			
RHR-DHR-AY	Fail to align RHR for CHR - ATWS	21.8 min.	19.6 min.	2.19E-02	3.25E-02	This action is applicable to ATWS scenarios with HP injection and successful SLC. Time available to align SPC depends upon time of SLC injection and whether the initiator is an isolation event (MSIV closure). The pre-EPU PRA assumes that 25 minutes are available (diagnosis time of 20 mins. and execution time of 5 mins.). This time is judged conservative. MNGP EPU MELLLA MAAP runs MNGPEPU7b, MNGPEPU7bx, MNGPEUP7c and MNGPEPU7cx show that with delayed SLC injection and no SPC initiation, critical impacts do not occur until about t=45 mins when the pool reaches 200F and HPCI operability become an issue. Although the 25 min. time available estimate from the pre-EPU is judged still appropriate for the EPU MELLLA condition, the EPU MELLLA risk assessment reduced this time available by 13% to t=21.8 mins (diagnosis time of 16.8 min. and execution time of 5 min.). The MELLLA+ risk assessment reduces the MELLLA time window for this action by an additional 10% to t=19.6 mins (diagnosis time of 14.6 min. and execution time of 5 min.). ASEP Median TRC curve.

Table 4.1-11

RE-ASSESSMENT OF OPERATOR ACTION HEPs POTENTIALLY IMPACTED BY MELLLA+

Action ID	Action Description	Allowable Action Time		MELLLA HEP	MELLLA+ HEP	Comment
		EPU MELLLA	EPU MELLLA+			
SD-NOTRIPY	Fail to prevent turbine trip while shutting down	4.4 min.	4 min.	2.27E-01	2.50E-01	This action is for bypassing the MSIV low level interlocks and is applicable to ATWS scenarios with the MSIVs open. The time available depends upon a number of factors, such as which HP systems are available and how long operators take to reduce level. The MELLLA PRA assumes the available diagnosis time is t=4.4 min. The MELLLA+ risk assessment reduces the MELLLA time window for this action by an additional 10% to t=4 mins. ASEP Median TRC curve.
SLC-CRD--Y	Fail to inject boron using CRDH	n/a	n/a	6.30E-03	6.30E-03	Execution Error: HEP calculation not directly influenced by available time window. Diagnosis contribution treated by a separate basic event.
SLC-INI-LY	Fail to initiate SLC - long time available	>1 hr.	>1 hr.	4.00E-04	4.00E-04	This action error applies to ATWS scenarios in which the turbine is online. An indefinite, long time is available to the operator; the MELLLA PRA assumes > 1 hr. available. This timing assumption is not changed by MELLLA+. ASEP Lower Bound TRC curve. In addition, the HEP is dominated by execution error.
SLC-INI-SY	Fail to initiate SLC - short time available	11.8 min.	10.6 min.	6.17E-03	8.64E-03	The MELLLA+ risk assessment reduces the MELLLA time window for this action by an additional 10% to t=10.6 mins. ASEP Lower Bound TRC curve.
SLC-LVL1-Y	Fail to control reactor level (fail SLC), given nominal conditions	8.7 min.	7.8 min.	1.53E-02	1.92E-02	The MELLLA+ risk assessment reduces the MELLLA time window for this action by an additional 10% to t=7.8 mins (diagnosis time of 7.3 min. and execution time of 0.5 min.). ASEP Lower Bound TRC curve.

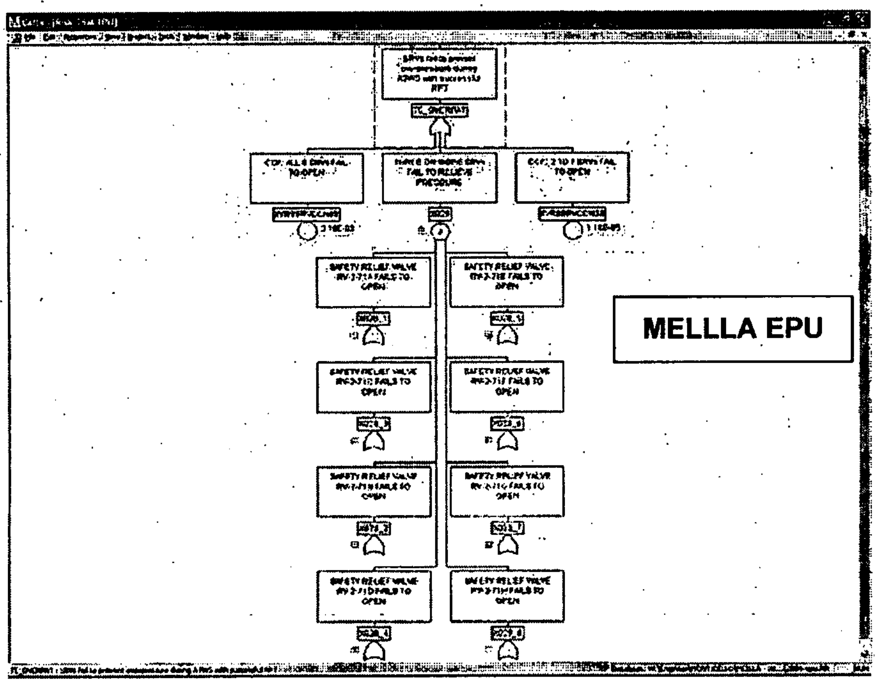
Table 4.1-11

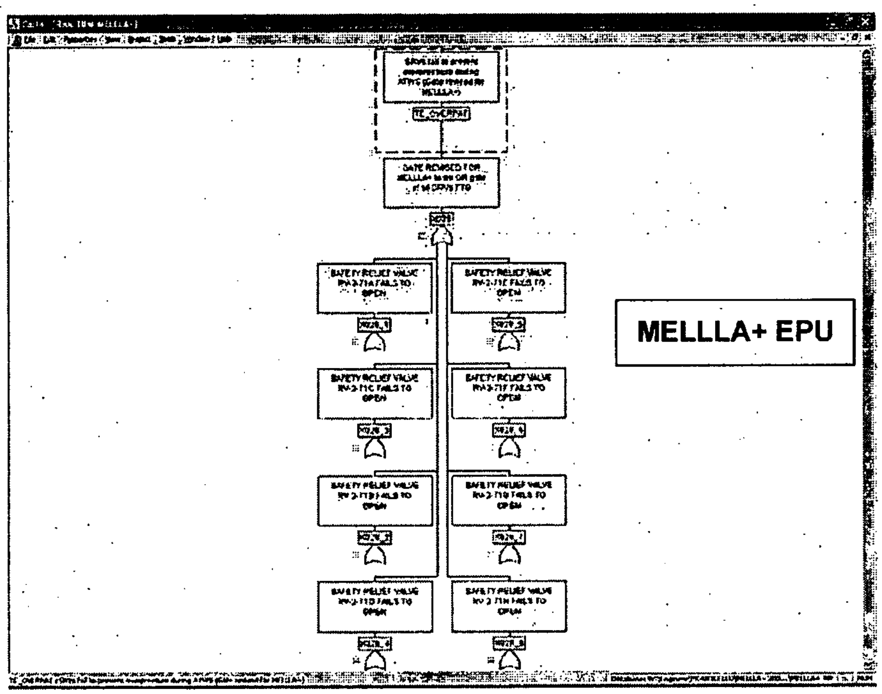
RE-ASSESSMENT OF OPERATOR ACTION HEPs POTENTIALLY IMPACTED BY MELLLA+

Action ID	Action Description	Allowable Action Time		MELLLA HEP	MELLLA+ HEP	Comment
		EPU MELLLA	EPU MELLLA+			
SLC-LVL2-Y	Fail to control reactor level (fail SLC), given challenging conditions	11.8 min.	10.6 min.	1.97E-02	2.27E-02	The MELLLA+ risk assessment reduces the MELLLA time window for this action by an additional 10% to t=10.6 mins (diagnosis time of 10.1 min. and execution time of 0.5 min.). ASEP Lower Bound TRC curve.

Figure 4.1-1

EDITS TO ATWS OVERPRESSURIZATION FAULT TREE LOGIC (Base Case)





4.2 LEVEL 1 PRA

Section 4.1 summarized possible effects of MELLLA+ by examining each of the PRA elements. This section examines possible MELLLA+ effects from the perspective of accident sequence progression. The dominant accident scenario types (classes) that can lead to core damage are examined with respect to the changes in the individual PRA elements discussed in Section 4.1.

Loss of Inventory Makeup Transients

The following bullets summarize key issues:

- MELLLA+ has no direct impact on transient initiating event frequencies.
- MELLLA+ has no impact on success criteria.
- MELLLA+ has no impact on accident sequence progression.
- MELLLA+ has no impact on transient accident sequence timing
- MELLLA+ has no impact on component failure rates

As such, no changes to the existing risk profile associated with loss of inventory makeup accidents result due to MELLLA+.

Station Blackout (SBO)

The following bullets summarize key issues:

- MELLLA+ has no impact on the LOOP initiating event frequency.
- MELLLA+ has no impact on success criteria.

- MELLLA+ has no impact on accident sequence progression.
- MELLLA+ has no impact on LOOP/SBO accident sequence timing
- MELLLA+ has no impact on component failure rates

As such, no changes to the existing risk profile associated with station blackout accidents result due to MELLLA+.

Loss of Containment Heat Removal

The following bullets summarize key issues:

- MELLLA+ has no direct impact on initiating event frequencies.
- MELLLA+ has no impact on success criteria.
- MELLLA+ has no impact on accident sequence progression.
- MELLLA+ has no impact on transient accident sequence timing
- MELLLA+ has no impact on component failure rates
- MELLLA+ does not involve any changes to the containment structure or capability.

As such, no changes to the existing risk profile associated with loss of containment heat removal accidents result due to MELLLA+.

LOCAs

The following bullets summarize key issues:

- MELLLA+ has no impact on LOCA initiating event frequencies.
- MELLLA+ has no impact on success criteria.

- MELLLA+ has no impact on accident sequence progression.
- MELLLA+ has no impact on LOCA accident sequence timing
- MELLLA+ has no impact on component failure rates
- The containment analyses for LOCA under MELLLA+ conditions indicate that dynamic loads on containment remain acceptable.

As such, no changes to the existing risk profile associated with LOCA accidents result due to MELLLA+. The same general conclusion applies to ISLOCA accidents and LOCA breaks outside containment.

<u>ATWS</u>

The following bullets summarize key issues:

- MELLLA+ has no direct impact on initiating event frequencies.
- 8 of 8 SRVs are required for the MELLLA+ condition for RPV initial overpressure protection during an ATWS scenario (7 of 8 SRVs were required for the MELLLA condition).
- The MELLLA+ operating region is postulated to result in higher potential ATWS power, thus reducing operator action timings in ATWS scenarios.
- The MELLLA+ higher potential ATWS power can be postulated to increase the stuck open relief valve probability during an ATWS.
- MELLLA+ has no impact on accident sequence progression.
- MELLLA+ has no impact on component failure rates
- MELLLA+ does not involve any changes to the containment structure or capability.

As such, changes are expected to the existing risk profile associated with ATWS accidents due to MELLLA+.

4.3 INTERNAL FIRES INDUCED RISK

Monticello does not currently maintain a fire PRA.

The Monticello plant risk due to internal fires was evaluated in 1995 as part of the MNGP Individual Plant Examination of External Events (IPEEE) Submittal. [10] EPRI FIVE Methodology and Fire PRA Implementation Guide screening approaches and data were used to perform the MNGP IPEEE fire PRA study. [5,6,7]

Consistent with the FIVE Methodology and the requests of the NRC IPEEE Program, the MNGP IPEEE fire PRA is an analysis that identifies the most risk significant fire areas in the plant using a screening process and by calculating conservative core damage frequencies for fire scenarios. As such, the accident sequence frequencies calculated for the MNGP fire PRA are not a best estimate calculation of plant fire risk and are not acceptable for direct integration with the best estimate MNGP internal events PRA results for comparison with Regulatory Guide 1.174 acceptance guidelines.

MELLLA+ does not involve any plant changes that directly impact fire accident initiation or mitigation (i.e., no changes to fire protection systems, combustible loadings, or addition of new ignition sources). The only postulated impact on the internal fire risk profile would be due to the potential ATWS impacts discussed previously. However, fire-initiated ATWS scenarios are a non-significant contributor to the plant risk profile.

NUREG/CR-6850, Volume 2, Section 2.5.1 (page 2-7) [22] provides the following directions for selecting components and accident scenarios to be examined in an internal fire PRA:

> *"The types of sequences that could generally be eliminated from the PRA include the following...Sequences associated with events that, while it is possible that the fire could cause the event, a low-frequency argument can be justified. For example, it can often be easily demonstrated that anticipated transient without scram (ATWS) sequences do not need to be treated in the Fire PRA because fire-induced failures will almost certainly remove power from the control rods (resulting in a trip), rather than cause a "failure-to-scram" condition. Additionally, fire frequencies multiplied by the independent failure-to-scram probability can usually be argued to be small contributors to fire risk."*

As can be seen from the NUREG/CR-6850 excerpt above, fire-induced ATWS contributors are generally acknowledged as non-significant contributors to the fire risk profile.

Based on this discussion, it is reasonably concluded that the risk contribution of fire initiated ATWS is non-significant and does not impact the decision-making for the proposed MELLLA+ change.

This fire risk impact assessment did not involve re-performing the MNGP IPEEE internal fire analysis. Similarly, plant walkdowns for internal fire risk issues were not re-performed in support of this assessment.

4.4 SEISMIC RISK

Monticello does not currently maintain a seismic PRA.

The Monticello seismic risk analysis was performed as part of the Individual Plant Examination of External Events (IPEEE). [10] Monticello performed a seismic margins assessment (SMA) following the guidance of NUREG-1407 and EPRI NP-6041. The SMA is a deterministic evaluation process that does not calculate risk on a probabilistic basis. No core damage frequency sequences were quantified as part of the seismic risk evaluation.

Based on a review of the Monticello IPEEE and the key general conclusions identified earlier in this assessment, the conclusions of the SMA are judged to be unaffected by MELLLA+. MELLLA+ has no impact on the seismic qualifications of systems, structures and components (SSCs). The only postulated impact on the seismic risk profile would be due to the potential ATWS impacts discussed previously. However, seismic-initiated ATWS scenarios are a non-significant contributor to the plant risk profile.

The NUREG/CR-4551 study performed severe accident analysis risk assessments for five nuclear power plants, including Peach Bottom Atomic Power Station. The Peach Bottom NUREG/CR-4551 analysis addressed both internal and external events, including seismic initiators. It is reasonably assumed that the seismic ATWS risk portion of the Peach Bottom NUREG/CR-4551 analysis is generically applicable to Monticello due to the similarity of the plant design and systems.

The NUREG/CR-4551 Peach Bottom seismic analysis screened seismic-induced ATWS accident sequences as non-significant contributors (<1%) to the plant seismic CDF.

Based on this discussion, it is reasonably concluded that the risk contribution of seismically induced ATWS is non-significant and does not impact the decision-making for the proposed MELLLA+ change.

This seismic impact assessment did not involve re-performing the MNGP IPEEE SMA. Similarly, SMA plant walkdowns were not re-performed in support of this assessment.

4.5 OTHER EXTERNAL EVENTS RISK

In addition to internal fires and seismic events, the MNGP IPEEE Submittal analyzed a variety of other external hazards:

- High Winds/Tornadoes
- External Floods

- Transportation and Nearby Facility Accidents
- Other External Hazards

The MNGP IPEEE analysis of high winds, tornadoes, external floods, transportation accidents, nearby facility accidents, and other external hazards was accomplished by reviewing the plant environs against regulatory requirements regarding these hazards. Based upon this review, it was concluded that MNGP meets the applicable NRC Standard Review Plan requirements and therefore has an acceptably low risk with respect to these hazards.

Note that internal flooding scenarios are analyzed as internal events and already are included in the MGNP internal events at-power PRA used in this MELLLA+ risk assessment.

4.6 SHUTDOWN RISK

The following qualitative discussion applies to the shutdown conditions of Hot Shutdown (Mode 3), Cold Shutdown (Mode 4), and Refueling (Mode 5). The MELLLA+ risk impact during the transitional periods such as at-power (Mode 1) to Hot Shutdown and Startup (Mode 2) to at-power is judged to be subsumed by the at-power Level 1 PRA. This is consistent with the U.S. PRA industry, and with NRC Regulatory Guide 1.174 which states that not all aspects of risk need to be addressed for every application. While higher conditional risk states may be postulated during these transition periods, the short time frames involved produce an insignificant impact on the long-term annualized plant risk profile.

MELLLA+ has no impact on shutdown risk.

The following bullets summarize key issues:

- MELLLA+ has no impact on initiating events at shutdown. MELLLA+ does not create any new shutdown risk initiating event categories nor does MELLLA+ increase the frequency of initiating events at shutdown (e.g., loss of SDC, inadvertent drain down).
- MELLLA+ does not involve any system or plant changes that would impact success criteria during shutdown.
- MELLLA+ has no impact on the accident progression timings of accidents initiated at shutdown.
- MELLLA+ has no impact on system or component failure rates or availabilities for equipment used during shutdown activities.
- MELLLA+ has no impact on the scheduling of outage activities.
- MELLLA+ has no impact on operator actions or shutdown related procedures or processes.

As such, no changes to the existing shutdown risk profile result due to MELLLA+.

4.7 RADIONUCLIDE RELEASE (LEVEL 2 PRA)

The Level 2 PRA calculates the containment response under postulated severe accident conditions and provides an assessment of the containment adequacy. In the process of modeling severe accidents (i.e., the MAAP code), the complex plant structure has been reduced to a simplified mathematical model which uses basic thermal hydraulic principles and experimentally derived correlations to calculate the radionuclide release timing and magnitude. [9]

The following aspects of the Level 2 analysis are briefly discussed with respect to impacts postulated due to MELLLA+:

- Level 1 input
- Accident Progression
- Human Reliability Analysis

- Success Criteria
- Containment Capability
- Radionuclide Release Magnitude and Timing

<u>Level 1 Input</u>

The front-end evaluation (Level 1) involves the assessment of those scenarios that could lead to core damage. The subsequent treatment of mitigative actions and the inter-relationship with the containment after core damage is then treated in the Containment Event Tree (Level 2).

In the Monticello Level 1 PRA, accident sequences are postulated that lead to core damage and potentially challenge containment. The Monticello Level 1 PRA has identified discrete accident sequences that contribute to the core damage frequency and represent the spectrum of possible challenges to containment.

The Level 1 core damage sequences are also directly propagated through the Level 2 PRA containment event trees. Changes to the Level 1 PRA modeling directly impact the Level 2 PRA results. However, the percentage increase in total CDF due to MELLLA+ is not a direct translation to the percentage increase in total LERF. Therefore, the Level 2 at-power internal events PRA model is also requantified as part of this MELLLA+ risk assessment.

<u>Accident Progression</u>

As discussed earlier in Section 4.1.3, MELLLA+ does not change the plant configuration and operation in a manner that produces new accident sequences or changes accident sequence progression phenomenon. This is particularly true in the case of the Level 2 post-core damage accident progression phenomena. MELLLA+ does not involve any plant changes that impact modeling of post-core damage accident progression.

Therefore, no changes are made as part of this risk assessment to the Level 2 PRA accident sequence models (either in structure or basic event phenomenon probabilities).

Human Reliability Analysis

As discussed previously, the MELLLA+ operating region is postulated to result in higher potential ATWS power, thus reducing operator action timings in ATWS scenarios. These ATWS operator action adjustments for MELLLA+ are addressed in the Level 1 models. ATWS core damage accidents that progress into the Level 2 PRA experience just one additional operator action of note - depressurize the RPV post-core damage and prior to vessel breach. The operator response time window for this action is defined with respect to the onset of core damage and defined by core melt progression issues, and not directly related to MELLLA+ ATWS timing issues.

Therefore, no changes are made as part of this risk assessment to Level 2 HEPs.

Success Criteria

No changes in success criteria have been identified with regard to the Level 2 containment evaluation (refer to Section 4.1.2.8 of this report). Therefore, no changes to Level 2 modeling with respect to success criteria are made as part of this risk assessment.

Containment Capability

As discussed in Section 4.1.9 earlier in this report, no issues have been identified with respect to MELLLA+ that have any impact on the capacity of the MNGP containment as analyzed in the PRA.

The MNGP containment capacity with respect to severe accidents is analyzed in the PRA using plant specific structural analyses as well as information from industry studies and experiments. The MNGP containment capacity is assessed in the Level 2 PRA with respect to following challenge categories [9]:

1) <u>Pressure Induced Containment Challenge</u>: Containment pressures may increase from normal operating pressure along a saturation curve to very high pressures (i.e., beyond 100 psi), during accidents involving:

   - Insufficient long term decay heat removal; and
   - Inadequate reactivity control and consequential inadequate containment heat removal.

2) <u>Temperature Induced Containment Challenge</u>: Containment temperatures can rise without substantial pressure increases if containment pressure control measures (e.g., venting) are available. In such cases, containment temperature may increase to above 1000°F with the containment at less than design pressure during accidents involving core melt progression.

3) <u>Combined Pressure and Temperature Induced Containment Challenge</u>: Containment pressures and temperatures can both rise during a severe accident due to molten debris effects following RPV failure and subsequent core concrete interaction. For instance:

   - Containment temperatures can rise from approximately 300°F at core melt initiation to above 1000°F in time frames on the order of 10 hours.
   - Additionally, containment pressure can rise due to non-condensible gas generation and RPV blowdown in the range of 40 psig to 100 psig over this same time frame.

4) <u>Containment Dynamic Loading</u>: Postulated accident sequences cover a broad spectrum of events, including failure of the containment under degraded conditions for which the following may be present:

   - High suppression pool temperature with substantial continuous blowdown occurring (i.e., equivalent to greater than 6% power), or

- High suppression pool water levels coupled with equivalent LOCA loads and the consequential hydrodynamic loads, or
- Other energetic events, such as steam explosion.

5) <u>Containment Isolation</u>: Containment isolation failure during a core damage event is modeled as leading to large early releases in the MNGP Level 2.

MELLLA+ does not involve any changes to the containment structure or capability, or the containment isolation system. Therefore, no changes to Level 2 modeling with respect to containment failure or containment isolation failure are made as part of this risk assessment.

<u>Release Magnitude and Timing</u>

The "Early" timing threshold is defined in the MNGP Level 2 PRA as a release from secondary containment beginning at 0 to 6 hours after declaration of a General Emergency. The 0-6 hour time frame is based upon experience data concerning non-nuclear offsite accident response and is conservatively (i.e., 0-4 hours is a justifiable "Early" range also used in industry BWR PRAs) assumed to include cases in which minimal offsite protection measures have been performed.

The "Large" magnitude threshold is defined in the MNGP Level 2 PRA as greater than 10% release of CsI inventory in the core. This is based on past industry studies that show once the average release fraction of CsI falls below approximately 0.1, the mean number of prompt fatalities is very small, or zero, except for a few outliers that correspond to pessimistic assumptions.

This release categorization and bases is consistent with U.S. BWR PRA industry techniques. [4, 22]

As discussed in Section 4.1.9, MELLLA+ has no impact on the PRA radionuclide release categorization. MELLLA+ has no impact on radionuclide release magnitude. While the timing of ATWS scenarios can see a minor impact (e.g., reduction of 10%), this postulated timing reduction has no impact on the release timing categorization of ATWS severe accidents because all ATWS releases are assigned the earliest release categorization ("Early") in the PRA.

Therefore, no changes to Level 2 modeling with respect to accident sequence release categorizations are made as part of this risk assessment.

Level 2 Impact Summary

Based on the above discussion, the impact of MELLLA+ on the MNGP Level 2 PRA results, independent of the Level 1 analysis, is judged to be minor. The only change in the Level 2 PRA is due to changes in the core damage accidents used as input to the Level 2 PRA quantification.

Section 5
CONCLUSIONS

The MELLLA+ planned implementation for Monticello has been reviewed to determine the net impact on the Monticello risk profile. This examination involved the identification and review of plant and procedural changes, plus assessment of changes to the risk spectrum due to the MELLLA+ changes and associated plant response during postulated accidents.

This risk assessment has been performed using as the base model the Monticello EPU MELLLA PRA ***average maintenance*** model (fault tree ***Risk-T&M-EPU.caf***). The 1995 MNGP IPEEE study is used to support the qualitative assessment of seismic, internal fires and other external events.

This section summarizes the risk impacts of the MELLLA+ implementation on the following areas:

- Level 1 Internal Events PRA
- Level 2 PRA
- Fire Induced Risk
- Seismic Induced Risk
- Other External Hazards
- Shutdown Risk

Guidelines from the NRC (Regulatory Guide 1.174) are followed to assess the change in risk as characterized by core damage frequency (CDF) and Large Early Release Frequency (LERF)

5.1 LEVEL 1 PRA

Table 5.1-1 provides a summary of the PRA model changes incorporated as a result of the MELLLA+ evaluation. Table 5.1-1 provides the following information:

- Basic event identification and description
- Basic event probability in the MELLLA reference model
- Revised probability for MELLLA+

A fault tree modeling structure change to the MNGP PRA was necessary to reflect the change to the SRV fault tree logic for RPV overpressure protection during an ATWS. All other model changes were changes to basic event probabilities (e.g., human error probability).

The MELLLA+ base case results in an increase to the at-power internal events PRA CDF from the MELLLA reference model value of 5.58E-6/yr to 5.85E-6/yr, an increase of 2.6E-7/yr. This initial base estimate is conservative; refer to Section 5.7 for sensitivities and determination of the best estimate of the risk impact.

5.2 LEVEL 2 PRA

The Level 2 PRA calculates the containment response under postulated severe accident conditions and provides an assessment of the containment adequacy.

The MELLLA+ base case results in an increase to the at-power internal events PRA LERF from the MELLLA reference model value of 3.64E-7/yr to 4.83E-7/yr, an increase of 1.2E-7/yr. This initial base estimate is conservative; refer to Section 5.7 for sensitivities and determination of the best estimate of the risk impact.

Table 5.1-1

BASE CASE: MNGP PRA MODEL CHANGES TO RELECT MELLLA+

Change	Parameter ID	Model Element Description	MELLLA Value	MELLLA+ Value
Human Error Probability (HEP) Changes to address reduced timings	RHR-DHR-AY	Fail to align RHR for CHR - ATWS	2.19E-02	3.25E-02
	SLC-INI-SY	Fail to initiate SLC - short time available	6.17E-03	8.64E-03
	SLC-LVL1-Y	Fail to control reactor level (fail SLC), given nominal conditions	1.53E-02	1.92E-02
	SLC-LVL2-Y	Fail to control reactor level (fail SLC), given challenging conditions	1.97E-02	2.27E-02
	DEP-02MN-Y	Fail RPV depressurization within 2 minutes	5.10E-01	1.00E+00
	SD-NOTRIPY	Fail to prevent turbine trip while shutting down	2.27E-01	2.50E-01
SORV Probability	XVR-ATWS-C	One or more relief valve fails to close - ATWS scenario	2.26E-02	2.49E-02
RPV Overpressure Protection for ATWS	Fault Tree Gate X028 (refer to Figure 4.1-1)	• Fault tree gate X028 revised from a 2/8 gate to an "OR" gate, such that failure of any single SRV to open will result in RPV overpressurization. • SRV CCF basic events removed as they are not applicable given just a single SRV failure is assumed to fail this function for the MELLLA+ condition.	n/a	n/a

5.3 FIRE INDUCED RISK

The risk contribution of fire initiated ATWS is non-significant and does not impact the decision-making for the proposed MELLLA+ change (refer to Section 4.3 of this report).

5.4 SEISMIC RISK

The risk contribution of seismically induced ATWS is non-significant and does not impact the decision-making for the proposed MELLLA+ change (refer to Section 4.4 of this report).

5.5 OTHER EXTERNAL HAZARDS

Based on review of the Monticello IPEEE, MELLLA+ has no significant impact on the plant risk profile associated with tornadoes, external floods, transportation accidents, and other external hazards. Refer to Section 4.5 of this report for further discussion.

5.6 SHUTDOWN RISK

MELLLA+ has no impact on shutdown risk (refer to Section 4.6 of this report).

5.7 QUANTITATIVE BOUNDS ON RISK CHANGE

5.7.1 Sensitivity Studies

As discussed in previous sections, the initial base case results are judged conservative. The conservative nature of the base case results are primarily due to the following two items: 1) assuming the design basis ODYN calculations that allow 0 SRVs OOS for isolation ATWS scenarios; and 2) conservative elements in the base MNGP PRA that become highlighted when 0 SRVs OOS for ATWS is assumed in the model.

One of the methods to provide valuable input into the decision-making process is to perform sensitivity calculations for situations with different assumed conditions to bound the results.

These sensitivity studies investigate the impact on the at-power internal events CDF and LERF and determine the best estimate case for this risk assessment. Nine (9) quantitative sensitivity cases are performed and discussed below.

<u>Sensitivity #1</u>

This sensitivity case addresses the dominant modeled impact in the risk calculation, i.e., 0 SRVs OOS for ATWS scenarios.

The ODYN software calculations performed for the MELLLA+ condition require all SRVs to be functional, no SRVs can be out of service, to maintain the RPV pressure spike below the ASME Service Level C limit of 1500 psig during an isolation ATWS event, such as an MSIV Closure ATWS (refer to MELLLA+ Task Report 0902, "ATWS"). Isolation ATWS scenario (e.g., MSIV Closure ATWS) calculations performed using the TRACG software are also documented in MELLLA+ Task Report 0902. The TRACG software calculations showed that 1 SRV can be OOS for an isolation ATWS scenario (e.g., MSIV Closure ATWS) and the RPV pressure spike remains below the ASME Service Level C limit.

As discussed in MELLLA+ Task Report 0902, TRACG calculations are best-estimate calculations compared to the more conservative licensing basis ODYN calculations.

This sensitivity case is performed by reversing the changes in the MELLLA+ model described for "Fault Tree Gate X028" in Table 5.1-1. All other parameters are maintained the same as the MELLLA+ base case. No changes to the MELLLA reference model are made for this sensitivity case.

The model changes made for this sensitivity case are summarized in Table 5.7-1.

Sensitivity #2

This sensitivity case addresses a non-significant conservative element in the MNGP PRA that is highlighted and becomes a significant contributor to the delta CDF and delta LERF when 0 SRVs OOS for ATWS scenarios is assumed in the MELLLA+ base case calculation. This conservative element is the pre-initiator error probability assumed for "failure to restore post-maintenance" for the SRVs. This out of service probability is modeled in the PRA for each SRV, in addition to the other failure mode for "SRV fails to open".

The value used in the MNGP base model for the probability that an SRV may be inadvertently improperly installed during an outage and exist in that inoperable configuration at-power is 8.1E-3 per SRV. This probability is judged an order of magnitude too high. Using the ASEP pre-initiator HEP method in the EPRI HRA Calculator software along with the following assumptions, a revised error rate of 3E-4 is calculated for use in this sensitivity case:

- SRV is replaced or receives maintenance once per fuel cycle
- Opportunity exists to install/restore SRV incorrectly such that it is not functional in safety relief mode
- SRV inoperability cannot be detected until the subsequent refuel outage
- ASEP methodology base human error probability (BHEP) is reasonably assumed to apply
- ASEP BHEP Recovery potential:
  - No compelling status/signal in MCR of SRV inoperable status
  - Post-maintenance test/calibration performed

- Independent verification of post-maintenance test/calibration not assumed
- Daily or shift checks do not apply

This error rate change is made to the following basic events in the MELLLA reference model and the MELLLA+ model (all other parameters are maintained the same):

- XVR2-71AXZ, "SRV 2-71A Improperly Returned to Service".
- XVR2-71BXZ, "SRV 2-71B Improperly Returned to Service"
- XVR2-71CXZ, "SRV 2-71C Improperly Returned to Service"
- XVR2-71DXZ, "SRV 2-71D Improperly Returned to Service"
- XVR2-71EXZ, "SRV 2-71E Improperly Returned to Service"
- XVR2-71FXZ, "SRV 2-71F Improperly Returned to Service"
- XVR2-71GXZ, "SRV 2-71G Improperly Returned to Service"
- XVR2-71HXZ, "SRV 2-71H Improperly Returned to Service"

The model changes made for this sensitivity case are summarized in Table 5.7-1.

Sensitivity #3

This sensitivity case increases the Turbine Trip transient initiator frequency to investigate the impact on the delta risk calculations for postulated long-term increase in the frequency of plant transients due to operation in the proposed MELLLA+ region. The revision to the Turbine Trip frequency using an approach that assumes an additional turbine trip is experienced in the first year following start-up in the MELLLA+ condition and an additional 0.5 event in the second year. This approach postulates a trip in the first year specifically due to MELLLA+, and then assumes a 50% likelihood that plant corrections to address the root cause of the trip do not correct the issue and a trip occurs again. No such increases in frequency of transients are expected.

The change in the long-term average of the Turbine Trip (IE_TURB-TRIP) frequency is calculated as follows for this sensitivity case:

- Base long-term Turbine Trip frequency is 9.90E-1/yr
- 10 years is used as the "long-term" data period
- End of 10 years does not reach the end-of-life portion of the bathtub curve
- Revised Turbine Trip frequency for this sensitivity case is calculated as:

$$\frac{(10 \times 0.99) + 1.0 + 0.5}{10} = 1.14/yr$$

This change is made to the MELLLA+ model. All other parameters are maintained the same as the MELLLA+ base case. No changes to the MELLLA reference model are made for this sensitivity case.

The model changes made for this sensitivity case are summarized in Table 5.7-1.

Sensitivity #4

This sensitivity case conservatively assumes that the potential impact on transient initiator frequencies is manifested in the MSIV Closure initiator frequency and not the Turbine Trip frequency. The MNGP base MSIV Closure initiator frequency (IE_MSIV) of 3.80E-2 is revised in this sensitivity case in the same manner as that discussed in Sensitivity Case #1:

$$\frac{(10 \times 3.80E\text{-}2) + 1 + 0.5}{10} = 1.88E\text{-}1/yr$$

This change is made to the MELLLA+ model. All other parameters are maintained the same as the MELLLA+ base case. No changes to the MELLLA reference model are made for this sensitivity case.

The model changes made for this sensitivity case are summarized in Table 5.7-1.

<u>Sensitivity #5</u>

This case addresses the sensitivity of a dominant contributor to the delta risk results - the scram failure probability.

The MNGP base PRA uses the current industry accepted scram failure probabilities, based on NRC study NUREG-5500:

- LASCRAMMEC, "FAILURE TO SCRAM (Mechanical)" = 2.1E-6/demand
- LASCRAMRPS, "FAILURE TO SCRAM (RPS)" = 3.8E-6/demand

Prior to NRC study NUREG-5500, the generic industry scram failure probabilities for a BWR PRA were significantly higher (1E-5/demand for mechanical scram failure and 2E-5/demand for electrical scram failure), based on estimates from the Utility Working Group on ATWS circa 1980.

This sensitivity study conservatively uses these older higher scram failure probabilities for basic events LASCRAMMEC and LASCRAMRPS. These basic event probability changes are made to both the MELLLA reference model and the MELLLA+ model (all other parameters are maintained the same).

The model changes made for this sensitivity case are summarized in Table 5.7-1.

Sensitivity #6

This case addresses the sensitivity of the delta risk results to the ATWS operator action error rates.

This sensitivity case assumes no impact on the ATWS human error probabilities (i.e., the ATWS HEPs in the MELLLA PRA model are maintained unchanged in the MELLLA+ model). All other parameters are maintained the same as the MELLLA+ base case. No changes to the MELLLA reference model are made for this sensitivity case.

The model changes made for this sensitivity case are summarized in Table 5.7-1.

Sensitivity #7

Similar to Sensitivity Case #6, this case addresses the sensitivity of the delta risk results to the ATWS operator action error rates.

This sensitivity case assumes the ATWS human error probabilities in the MELLLA PRA model are doubled for the MELLLA+ condition. All other parameters are maintained the same as the MELLLA+ base case. No changes to the MELLLA reference model are made for this sensitivity case.

The model changes made for this sensitivity case are summarized in Table 5.7-1.

Sensitivity #8

This sensitivity case combines the changes of Sensitivity Case #1 (best-estimate TRACG calculation) and Sensitivity Case #2 (refined SRV OOS probability). All other parameters are maintained the same. The model changes made for this sensitivity case are summarized in Table 5.7-1.

This case is judged the best-estimate case of the MELLLA+ risk assessment quantification cases.

Sensitivity #9

This sensitivity case combines the changes of Sensitivity Case #1 (best-estimate TRACG calculation), Sensitivity Case #2 (refined SRV OOS probability), Sensitivity Case #3 (Turbine Trip frequency increase postulated) and Sensitivity Case #5 (higher scram failure probability). All other parameters are maintained the same. The model changes made for this sensitivity case are summarized in Table 5.7-1.

5.7.1.2 Sensitivity Results

The results of the nine (9) sensitivity cases performed in support of this risk assessment are provided in Table 5.7-1. The results of the sensitivity cases are summarized below:

- Base Case: The initial base case results yield a delta CDF in the RG 1.174 "very small" risk increase region and a delta LERF that exceeds the RG 1.174 "very small" threshold by a minor amount (entering the RG 1.174 "small" risk increase region). These base case results are conservative. The conservative nature of the base case results are primarily due to the following two items: 1) assuming the design basis ODYN calculations that allow 0 SRVs OOS for isolation ATWS scenarios; and 2) conservative elements in the base MNGP PRA that become highlighted when 0 SRVs OOS for ATWS is assumed in the model.
- Sensitivity #1: This case shows that if the TRACG calculations for ATWS (as opposed to the more conservative licensing basis ODYN calculations) are used in the risk assessment to allow 1 SRV OOS for an isolation ATWS scenario then both the delta CDF and the delta LERF results are lower than the conservative base case and both are in the "very small" risk increase region of RG 1.174.

- Sensitivity #2: This case addresses the conservative failure probability used in the MNGP base PRA for an SRV being unavailable due to postulated maintenance errors during a previous outage. This conservative probability is not significant to the MNGP base PRA but becomes significant to the delta risk results in this study when 0 SRVs OOS is assumed required for isolation ATWS scenarios. This sensitivity case employs a more reasonable estimate using human reliability analysis techniques. This case shows that using a more realistic probability for SRVs being unavailable due to maintenance errors results in both the delta CDF and the delta LERF being lower than the conservative base case and both being in the "very small" risk increase region of RG 1.174.

- Sensitivity #3: Operation in the MELLLA+ region and the associated plant changes have no direct impact on calculated initiating event frequencies. This sensitivity case postulates an increase in the transient initiating event frequency due to unknown causes due to operation in the MELLLA+ region. The Turbine Trip with bypass initiator frequency is adjusted in this case. This case results in the same conclusions as the conservative base case (i.e., delta CDF in the RG 1.174 "very small" risk increase region and delta LERF exceeds the RG 1.174 "very small" threshold by a minor amount).

- Sensitivity #4: This case is the same as Sensitivity Case #3 except the MSIV Closure initiator frequency is adjusted in this case. This case results in the same conclusions as the conservative base case (i.e., delta CDF in the RG 1.174 "very small" risk increase region and delta LERF exceeds the RG 1.174 "very small" threshold by a minor amount).

- Sensitivity #5: As the postulated risk increases due to MELLLA+ relate primarily to ATWS scenarios, this case adjusts the failure to scram probabilities in the model. This conservative sensitivity employs the higher failure to scram probabilities used earlier in the PRA industry. This case results in higher delta risk results than the conservative base case. In this case, both the delta CDF and the delta LERF results are in the "small" risk increase region of RG 1.174. This conservative case shows that the even if the older obsolete industry scram failure probabilities were to be assumed, the delta risk results do not exceed the "small" risk region.

- Sensitivity #6: The primary impact on the calculated delta risk results is due to an assumed increase in ATWS power due to MELLLA+. The assumed increase in ATWS power is actually a potential condition depending upon the reactor power flow condition at the time of a plant trip. This sensitivity investigates the impact on the calculated risk results if the no impact on operator action timings (and thus no change to operator error rates) is assumed for the ATWS scenarios in the model. This case results in the same conclusions as the conservative base case (i.e., delta CDF in the RG 1.174 "very small" risk increase region and delta LERF exceeds the RG 1.174 "very small" threshold by a minor amount).

- Sensitivity #7: This case is analogous to Sensitivity Case #6, except in this case the impact on operator error rates is increased over that assumed in the base case. The base case quantification estimates an approximate 10% postulated increase in the ATWS power for MELLLA+ versus MELLLA. This sensitivity case assumes a 20% increase in ATWS power and adjusts the ATWS related HEPs accordingly. This case results in the same conclusions as the conservative base case (i.e., delta CDF in the RG 1.174 "very small" risk increase region and delta LERF exceeds the RG 1.174 "very small" threshold by a minor amount).

- Sensitivity #8 (Best Estimate Case): This case combines Sensitivities #1 and #2, addressing both key conservative issues in the base quantification. This sensitivity uses the TRACG ATWS calculations that show 1 SRV OOS during an isolation (e.g., MSIV closure) ATWS scenario is sufficient to prevent RPV overpressurization. This sensitivity also uses a more realistic value for an SRV being unavailable due to postulated maintenance errors in a previous outage. This case is the Best Estimate calculation in this risk assessment. This case results in both the delta CDF and the delta LERF being lower than the conservative base case and both being in the "very small" risk increase region of RG 1.174.

- Sensitivity #9: This case combines the Best Estimate case (Sensitivity #8) with the conservative failure to scram probability of Sensitivity #5. This case results in the same conclusions as the conservative base case (i.e., delta CDF in the RG 1.174 "very small" risk increase region and delta LERF exceeds the RG 1.174 "very small" threshold by a minor amount).

5.7.2 Results Summary

A number of quantitative sensitivities were performed to investigate the impact on delta CDF and delta LERF results for the proposed MELLLA+ operating regime. Refer to Table 5.7-1 for a summary of the results.

The best estimate of the risk increase for at-power internal events due to MELLLA+ is a delta CDF of 7.36E-8. The best estimate at-power internal events LERF increase due to MELLLA+ is a delta LERF of 1.62E-8.

Using the NRC guidelines established in Regulatory Guide 1.174 and the calculated results from the Level 1 and 2 PRA, the best estimate for the CDF risk increase (7.36E-8/yr) and the best estimate for the LERF increase (1.62E-8/yr) are both within Region III (i.e., changes that represent very small risk changes).

Based on these results, the proposed MNGP MELLLA+ operating regime is acceptable on a risk basis.

Table 5.7-1

RESULTS OF MNGP MELLLA+ PRA SENSITIVITY CASES

Parameter ID	MNGP MELLLA PRA	MELLLA+ Base Case	Sensitivity Case #1	Sensitivity Case #2	Sensitivity Case #3	Sensitivity Case #4	Sensitivity Case #5	Sensitivity Case #6	Sensitivity Case #7	[Best Estimate] Sensitivity Case #8	Sensitivity Case #9
ATWS HEPs[1]	MELLLA PRA (Tbl 4.1-11)	MELLLA+ Values (Tbl 4.1-11)	MELLLA+ Values (Tbl 4.1-11)	MELLLA+ Values (Tbl 4.1-11)	MELLLA+ Values (Tbl 4.1-11)	MELLLA+ Values (Tbl 4.1-11)	MELLLA+ Values (Tbl 4.1-11)	MELLLA PRA (Tbl 4.1-11)	2X MELLLA PRA Values	MELLLA+ Values (Tbl 4.1-11)	MELLLA+ Values (Tbl 4.1-11)
SORV Probability[2]	2.26E-2	2.49E-2	MELLLA+ Base Value	MELLLA+ Base Value	MELLLA+ Base Value	MELLLA+ Base Value	MELLLA+ Base Value	MELLLA+ Base Value	MELLLA+ Base Value	MELLLA+ Base Value	MELLLA+ Base Value
SRVs Required for ATWS[3]	7/8	8/8	7/8	8/8	8/8	8/8	8/8	8/8	8/8	7/8	7/8
SRV OOS Probability[4]	8.10E-3	MELLLA PRA Value	MELLLA PRA Value	3.0E-4	MELLLA PRA Value	MELLLA PRA Value	MELLLA PRA Value	MELLLA PRA Value	MELLLA PRA Value	3.0E-4	3.0E-4
Turbine Trip IE[5]	9.90E-1	MELLLA PRA Value	MELLLA PRA Value	MELLLA PRA Value	1.14	MELLLA PRA Value	MELLLA PRA Value	MELLLA PRA Value	MELLLA PRA Value	MELLLA PRA Value	1.14
MSIV Closure IE[6]	3.80E-2	MELLLA PRA Value	MELLLA PRA Value	MELLLA PRA Value	MELLLA PRA Value	1.88E-01	MELLLA PRA Value	MELLLA PRA Value	MELLLA PRA Value	MELLLA PRA Value	MELLLA PRA Value
Scram Failure Probabilities[7]	2.1E-6 (Mech) 3.8E-6 (Elec)	MELLLA PRA Values	MELLLA PRA Values	MELLLA PRA Values	MELLLA PRA Values	MELLLA PRA Values	1E-5 (Mech) 2E-5 (Elec)	MELLLA PRA Values	MELLLA PRA Values	MELLLA PRA Values	1E-5 (Mech) 2E-5 (Elec)
CDF:	5.58E-06	5.85E-06	5.66E-06	5.66E-06 (5.58E-6)	5.93E-06	5.92E-06	8.05E-06 (6.77E-6)	5.77E-06	5.91E-06	5.65E-06 (5.58E-6)	7.29E-06 (6.75E-6)
delta CDF[9]:	-	2.64E-07	7.36E-08	8.06E-08[8]	3.43E-07	3.41E-07	1.29E-06[8]	1.87E-07	3.32E-07	**7.36E-08[8]**	5.41E-07[8]
LERF:	3.64E-07	4.83E-07	3.80E-07	3.82E-07 (3.62E-7)	5.10E-07	5.10E-07	1.43E-06 (8.57E-7)	4.66E-07	5.18E-07	3.78E-07 (3.62E-7)	9.94E-07 (8.44E-7)
delta LERF[9]:	-	1.19E-07	1.62E-08	2.08E-08[8]	1.46E-07	1.46E-07	5.75E-07[8]	1.02E-07	1.54E-07	**1.62E-08[8]**	1.50E-07[8]

Notes to Table 5.7-1:

(1) The ATWS HEPs are those shown in Table 5.1-1. Refer to Section 4.1.6 for discussion of adjustment to these HEPs for MELLLA+.

(2) The Stuck Open Relief Valve (SORV) probability in the MNGP PRA for an ATWS scenario is modeled with basic event XVR-ATWS-C. Refer to Section 4.1.2.6 for discussion of adjustment to this value for MELLLA+.

(3) Refer to Section 4.1.2.5 for the discussion of the MELLLA+ impact on the number of SRVs required for ATWS overpressure protection and how the MELLLA base PRA model is adjusted to reflect this issue. Refer to Section 5.7.1, Sensitivity Case #1, for discussion of the TRACG results and how the MELLLA+ PRA model is adjusted to reflect use of the TRACG results.

(4) The SRV OOS probability refers to the following pre-initiator HEPs in the MNGP PRA for SRVs not properly restored to operability post test/maintenance:
- XVR2-71AXZ, "SRV 2-71A Improperly Returned to Service"
- XVR2-71BXZ, "SRV 2-71B Improperly Returned to Service"
- XVR2-71CXZ, "SRV 2-71C Improperly Returned to Service"
- XVR2-71DXZ, "SRV 2-71D Improperly Returned to Service"
- XVR2-71EXZ, "SRV 2-71E Improperly Returned to Service"
- XVR2-71FXZ, "SRV 2-71F Improperly Returned to Service"
- XVR2-71GXZ, "SRV 2-71G Improperly Returned to Service"
- XVR2-71HXZ, "SRV 2-71H Improperly Returned to Service"

(5) The turbine trip initiating event frequency is modeled in the MNGP PRA with basic event IE_TURB-TRIP. Refer to Section 5.7.1, Sensitivity Case #3, for discussion of adjustment to this frequency as a sensitivity case.

(6) The MSIV closure initiating event frequency is modeled in the MNGP PRA with basic event IE_MSIV. Refer to Section 5.7.1, Sensitivity Case #4, for discussion of adjustment to this frequency as a sensitivity case.

(7) Scram failure is modeled in the MNGP PRA with the following two basic events: LASCRAMMEC, "Failure to Scram (Mechanical)", and LASCRAMRPS, "Failure to Scram (RPS)". Refer to Section 5.7.1, Sensitivity Case #5, for discussion of adjustment to these parameters as a sensitivity case.

(8) The sensitivity case involved changes to the MELLLA base reference model, thus these delta risk calculations are with respect to the revised MELLLA base CDF and LERF for this case (revised MELLLA base CDF and LERF shown in parenthetical).

(9) Delta risk results calculated using results with 3 decimal points; delta risk results rounded to 2 decimal points for summary in this table.

(10) Shaded cells show those parameters adjusted for the sensitivity case.

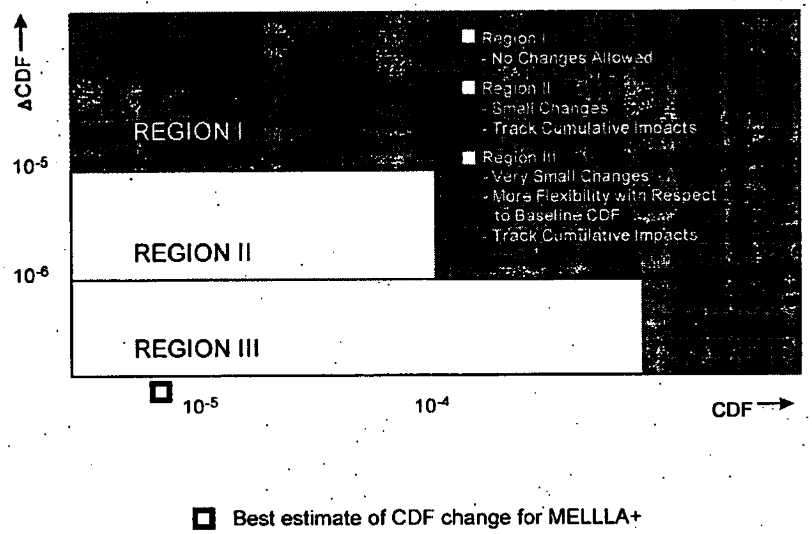


Figure 5.7-1 MNGP MELLLA+ Risk Assessment CDF Result Versus RG 1.174 Acceptance Guidelines* for Core Damage Frequency (CDF)

* The analysis will be subject to increased technical review and management attention as indicated by the darkness of the shading of the figure. In the context of the integrated decision-making, the boundaries between regions should not be interpreted as being definitive; the numerical values associated with defining the regions in the figure are to be interpreted as indicative values only.

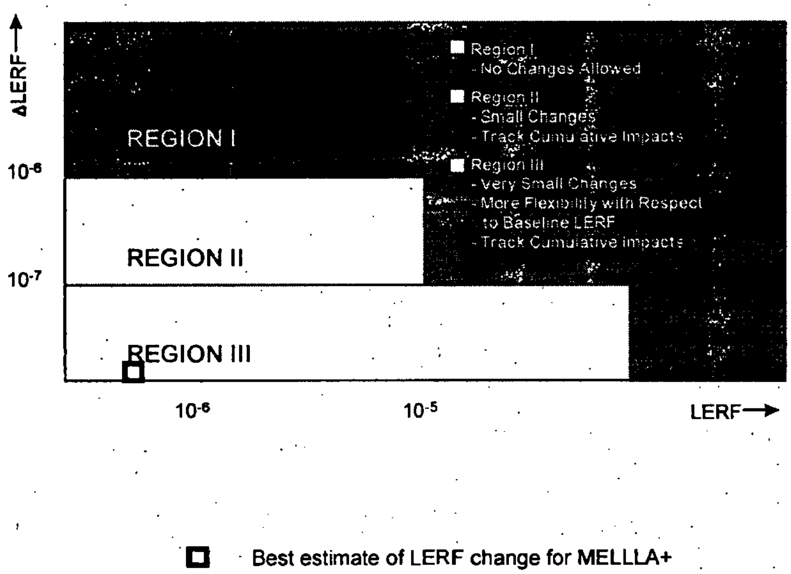


Figure 5.7-2 MNGP MELLLA+ Risk Assessment LERF Result Versus RG 1.174 Acceptance Guidelines* for (LERF)

* The analysis will be subject to increased technical review and management attention as indicated by the darkness of the shading of the figure. In the context of the integrated decision-making, the boundaries between regions should not be interpreted as being definitive; the numerical values associated with defining the regions in the figure are to be interpreted as indicative values only.

REFERENCES

[1] Monticello Nuclear Generating Plant, "Monticello Individual Plant Examination (IPE) Submittal", February 1992.

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[3] Idaho National Engineering and Environmental Laboratory, Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995, NUREG/CR-5750, February 1999.

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Appendix A

MONTICELLO PRA QUALITY

Appendix A
MONTICELLO PRA QUALITY

The quality of the Monticello PRA models used in performing this risk assessment is manifested by the following:

- Level of detail in PRA
- Maintenance of the PRA
- Comprehensive Critical Reviews

A.1 LEVEL OF DETAIL

The Monticello PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause events.

A.1.1 Initiating Events

The Monticello at-power PRA explicitly models a large number of internal initiating events:

- General transients
- LOCAs
- Support system failures
- Internal Flooding events

The initiating events explicitly modeled in the Monticello at-power PRA are summarized in Table A-1. The number of internal initiating events modeled in the Monticello at-power PRA is similar to the majority of U.S. BWR PRAs currently in use.

Table A-1

INITIATING EVENTS FOR MONTICELLO PRA

Initiator ID	Description
IE_125VDC	Loss of both divisions of 125V DC
IE_125VDC1	Loss of division I 125V DC power
IE_125VDC2	Loss of division II 125V DC power
IE_AIR	Loss of instrument air
IE_BUS13	Loss of electrical bus 13
IE_BUS14	Loss of electrical bus 14
IE_BUS15	Loss of electrical bus 15
IE_BUS16	Loss of electrical bus 16
IE_CRDH	Loss of CRDH
IE_DW-COOL	Loss of drywell cooling
IE_FW	Loss of feedwater
IE_LLOCA	Large LOCA initiating event
IE_LOOP	Loss of offsite power initiating event
IE_MLOCA	Medium LOCA initiating event
IE_MSIV	MSIV closure
IE_RBCCW	Loss of RBCCW
IE_REFLAB	Break in both reference legs
IE_REFLEGA	Break in 2-3-2A reference leg
IE_REFLEGB	Break in 2-3-2B reference leg
IE_SHUTDOWN	Manual shutdown of reactor
IE_SLOCA	Small LOCA initiating event
IE_SORV	Relief valve spuriously fails open
IE_SW	Loss of service water
IE_TURB-TRIP	Turbine trip

Table A-1

INITIATING EVENTS FOR MONTICELLO PRA

Initiator ID	Description
IE_VACUUM	Loss of condenser vacuum
IE_XLOCA	RPV rupture
ISLOCA	Interfacing Systems LOCA (numerous unique IEs)
Breaks Outside Containment	LOCA Outside Containment (Numerous unique IEs)
Floods	Internal Flooding initiators (numerous unique IEs)

A.1.2 System Models

The Monticello at-power PRA explicitly models a large number of frontline and support systems that are credited in the accident sequence analyses. The Monticello systems are modeled in the Monticello at-power PRA using fault tree structures for the majority of the systems. The number and level of detail of plant systems modeled in the Monticello at-power PRA is consistent with industry practices.

A.1.3 Operator Actions

The Monticello at-power PRA explicitly models a large number of operator actions:

- Pre-Initiator actions
- Post-Initiator actions
- Recovery Actions

Over one hundred operator actions are explicitly modeled. Given the large number of actions modeled in the Monticello at-power internal events PRA, a summary table of the individual actions modeled is not provided here.

The human error probabilities for the actions are modeled with accepted industry HRA techniques and include input based on discussion with plant operators, trainers, and other cognizant personnel.

The number of operator actions modeled in the Monticello at-power PRA, and the approach to their quantification is consistent with industry practices.

A.1.4 Common Cause Events

The Monticello at-power PRA explicitly models a large number of common cause component failures. Approximately two hundred common cause terms are included in the MNGP PRA. Given the large number of CCF terms modeled in the Monticello at-power internal events PRA, a summary table of them is not provided here. The number and level of detail of common cause component failures modeled in the Monticello at-power PRA is consistent with industry practices.

A.1.5 Level 2 PRA

The Monticello Level 2 links the Level 1 PRA accident sequences and systems logic with Level 2 containment event tree sequence logic and systems logic.

The following aspects of the Level 2 model reflect the more than adequate level of detail and scope:

- Dependencies from Level 1 accidents are carried forward directly into the Level 2 by transfer of sequences to ensure that their effects on Level 2 response is accurately treated.
- Virtually all phenomena identified by the NRC and industry for inclusion in BWR Mark I Level 2 analyses are treated explicitly within the model.
- The model truncation is sufficiently low to be consistent with the NEI PRA Peer Review Guidelines for Risk-Informed Applications.

A.2 MAINTENANCE OF PRA

MNGP IPE Submittal

The Monticello PRA was originally developed in response to the NRC Individual Plant Examination (IPE) Program, per NRC Generic Letter 88-20. The Monticello IPE was submitted in February 1992. [1]

The Monticello IPE submittal and the related NRC Staff Evaluation Report (SER) dated May 26, 1994 have been reviewed to identify references to vulnerabilities, weaknesses, and review findings. The results of the review, including the disposition of each observation are documented in the Table A-2. These findings have been previously incorporated into the PRA model where applicable and do not involve material impacts to the EPU or MELLLA+ risk assessments.

MNGP PRA Maintenance/Update Processes

The Monticello PRA model and documentation has been maintained living and is routinely and systematically updated to reflect the current plant configuration and to reflect the accumulation of additional plant operating history and component failure data. Controlled processes are in place at MNGP to identify plant modifications that impact the PRA. FP-PE-PRA-02, PRA Guideline for Model Maintenance and Update and PEI-05.01.03, PRA Guideline for Model Maintenance and Update, provide the processes and guidance for MNGP PRA model maintenance and periodic updates (refer to Reference [19]). In addition, plant changes and other relevant issues are assessed by the PRA group, and non-periodic updates are performed by PRA personnel if an identified plant change is assessed to involve a change to a system credited in the PRA or to significantly impact the calculated risk profile. PRA personnel are advised of pertinent plant modifications per procedure.

The Monticello PRA has been updated multiple times since the original IPE. A RG 1.200 update to the MNGP PRA is in progress at this time but is not available for use at this time (the conclusions of this study would not change).

The PRA models are routinely implemented and studied by plant PRA personnel in the performance of their duties.

Formal comprehensive model reviews are discussed in Section A.3.

Table A-2

SUMMARY OF DISPOSITION OF MNGP IPE OBSERVATIONS

Observation	Disposition
The IPE summary of major findings indicates that no new or unusual means were discovered by which core damage or containment failure could occur. No vulnerabilities, including internal flooding vulnerabilities, were identified as part of the IPE process for Monticello. No specific Unresolved Safety Issues or Generic Safety Issues were proposed for resolution as part of the IPE.	No disposition necessary.
The demineralizer bypass valve may not open upon a loss of instrument air.	A modification to the demineralizer bypass valve was performed to assure faster operation of the valve upon loss of instrument air.
Modification to the bottled N2 supply for the SRV solenoid valves was considered in order to preclude dependency on non-essential AC power.	Modification of alternate N2 supply to drywell pneumatics, including SRV solenoid valves, removed dependency on AC power. The PRA model reflects this in the current plant design.
Importance of reactor depressurization has been recommended for reinforcement in operator training.	Depressurization is a critical task that is assigned an associated Job Performance Measure in simulator scenarios. Also, the importance of depressurization is captured in EOP training.
The plant was encouraged to pursue relaxation of the drywell spray initiation limit through BWROG Severe Accident Working Committee.	The Drywell Spray Limit curve was modified subsequent to the IPE submittal to be consistent with restrictions that are intended to maintain primary containment integrity and protect equipment located within the primary containment.
Procedures were drafted to upgrade steps to load shed station batteries to extend battery life. Recommendations were made to develop alternate methods to supply station essential battery chargers.	The site Station Blackout procedure and other operating procedures provide guidance to preserve battery capacity as well as provide alternate methods to support battery charger operation using alternate power sources such as the # 13 Diesel Generator, the Security Diesel, or a portable generator.
Consider an AC independent means of decay heat removal in the form of the Hard Pipe Vent.	Monticello has installed a Hard Pipe Vent and has procedures to implement its use.
Improve capability of manually aligned, backup low pressure injection systems such as RHRSW through LPCI, Condensate Service Water, and Service Water to the Hotwell.	Procedures to provide makeup to the reactor vessel using low pressure alternate injection systems including RHRSW, Condensate Service Water, and Service Water to the Hotwell have been developed and implemented.
Write a procedure for emergency replenishment of the CSTs.	A procedure was written and a fill pipe has been fabricated to allow providing makeup water to the CSTs from an alternate water source such as a tanker truck or the fire water system.
Remove the actions for mechanically bound CRDs to a contingency procedure in the EOPs, so that the operator will focus on reactor shutdown with SLC.	Failure to scram actions have been optimized and proceduralized to coordinate an effective reactor shutdown using SBLC if necessary. Alternate Rod Injection is a separate procedure.
Test the CRD boron injection hoses to show that they are unlikely to fail due to collapse with SLC.	CRD boron injection hoses have recently been replaced based on shelf life considerations.

Planned or Implemented Modifications

The base reference model used in this risk assessment is the MNGP Level 1 and Level 2 at-power internal events EPU MELLLA PRA ***average maintenance*** model (fault tree ***Risk-T&M-EPU.caf***). This model is based on the MNGP 2005 PRA model of record and includes the model modifications to reflect EPU plant modifications already implemented and EPU planned plant modifications yet to be implemented, as well as other outstanding plant modifications that have been implemented or planned for implementation in the near future.

Most of the EPU planned modifications are already implemented in the plant. Outstanding EPU planned modifications include the BOP modifications and AC system conversion to 13.8 kV. All of the EPU mods are currently scheduled for completion before MELLLA+ implementation, and are integrated as appropriate into the PRA model (as described in References [15] and [19]) used in this MELLLA+ risk assessment.

In addition to EPU plant modifications that are reflected in the PRA model, other planned or implemented plant modifications not represented in the MNGP 2005 PRA model (used as the starting point to develop the EPU ***Risk-T&M-EPU.caf*** PRA model) have been integrated into the PRA model, as described in Reference [19].

The MELLLA+ plant changes and their impacts are implemented into the PRA model as summarized in Table 5.1-1 of this report.

A.3 COMPREHENSIVE CRITICAL REVIEWS

The Monticello PRA model has benefited from the following comprehensive technical reviews:

- NEI PRA Peer Review Process
- Recent assessments against the ASME PRA Standard

NEI PRA Peer Review

The Monticello internal events PRA received a formal industry PRA Peer Review in October 1997. [2] The purpose of the PRA Peer Review process is to provide a method for establishing the technical quality of a PRA for the spectrum of potential risk-informed plant licensing applications for which the PRA may be used. The PRA Peer Review process uses a team composed of PRA and system analysts, each with significant expertise in both PRA development and PRA applications. This team provides both an objective review of the PRA technical elements and a subjective assessment, based on their PRA experience, regarding the acceptability of the PRA elements. The team uses a set of checklists as a framework within which to evaluate the scope, comprehensiveness, completeness, and fidelity of the PRA products available.

The Monticello review team used the "BWROG PSA Peer Review Certification Implementation Guidelines", Revision 3, January 1997.

The general scope of the implementation of the PRA Peer Review includes review of eleven main technical elements, using checklist tables (to cover the elements and sub-elements), for an at-power PRA including internal events, internal flooding, and containment performance, with focus on large early release frequency (LERF). The eleven technical elements are shown in Tables A-3 through A-5.

The comments from the 1997 MNGP PRA Peer Review were prioritized by the review team into four categories A-D based upon importance to the completeness of the model. All comments in Categories A and B (recommended actions and items for consideration) were identified by the review team to Monticello as priority items to be resolved in the next model update. The comments in Categories C and D (good practices and editorial) were potential enhancements for consideration.

Elements that received a summary grade of 3 included Initiating Events, Thermal Hydraulic Analysis, Systems Analysis, Data Analysis, Human Reliability Analysis, Dependency Analysis, and Maintenance and Update Process. Technical elements are graded using a scale of 1 to 4 (4 being the highest grade and 3 being generally comparable to Capability Category II of the current ASME PRA Standard). The remaining elements: Accident Sequence Evaluation, Structural Response, Quantification and Results Interpretation, and Containment Performance Analysis, received a summary grade of 2 with average grade no lower than 2.5 for any element. Subsequent to the assignment of these grades, all A and B priority peer review comments for all eleven elements have been addressed by MNGP personnel and incorporated into the PRA model as appropriate.

Assessments Against ASME PRA Standard

Consistent with current industry practices, the MNGP has been compared against the ASME PRA Standard to identify areas of improvement. Three comparisons to the ASME PRA Standard have been performed in the past five years.

The first assessment against the ASME PRA Standard was performed in early 2004 by an independent consultation, Applied Reliability Engineering (ARE), Inc. That assessment compared the 2003 Monticello PRA model against a draft version of the ASME Standard and NRC draft Regulatory Guide DG-1122. Since that assessment, the MNGP PRA has evolved to include a much more extensive and detailed internal flooding analysis. Several other less significant model enhancements have occurred since the ARE, Inc. assessment, some of which were made to address insights from the assessment.

All open items identified in the 2004 Applied Reliability Engineering (ARE) Self Assessment of the 2003 version of the Monticello PRA model have been addressed and incorporated into the current model utilized for the MELLLA+ risk assessment, with the following exceptions:

- An open item related to Human Reliability Analysis element in NEI 00-02 recommended that a sensitivity study be re-performed to identify any changes to the list of key pre-initiator operator actions identified in the IPE. If any are found, it was recommended that the HRA analysis be re-performed using a more rigorous HRA approach, to reduce conservatism. The EPU and MELLLA+ implementation have no impact on pre-initiator HEP values; therefore, even if values were modified for some pre-initiator HEPs, these same values would apply to both the MELLLA risk quantification and the MELLLA+ risk quantification and thus a non-significant impact to the delta risk estimates; as such, this item has no impact on the conclusion of the MELLLA+ risk assessment.

- An open item recommends verifying data used to generate some initiating event frequencies has accounted for plant unavailability. It is recognized that the elimination of non-operational time may result in moderate increases in calculated initiating event frequencies. Like the above item, any changes in initiating event frequencies to reflect unavailability time would apply equally to both the MELLLA risk quantification and the MELLLA+ risk quantification and thus a non-significant impact to the delta risk estimates; as such, this item has no impact on the conclusion of the MELLLA+ risk assessment.

- An open item recommended considering performance of Bayesian updating for some additional events. Again, if this data enhancement was performed, it would apply equally to both the MELLLA risk quantification and the MELLLA+ risk quantification. No impact on the conclusion of the MELLLA+ risk assessment would result.

- Several recommendations were made to improve model documentation, conduct sensitivity studies and perform uncertainty analysis to meet enhanced capabilities set forth in the ASME standard. These enhancements were intentionally deferred to be accomplished in preparation for Monticello's upcoming formal Reg. Guide 1.200 Peer Review, and will not result in any significant impact on the results of the MELLLA+ risk assessment.

In conclusion, all open items from the ARE, Inc. self-assessment have been incorporated into the PRA model or have no significant impact on the MELLLA+ risk assessment.

A self-assessment of the 2005 MNGP PRA against the ASME Standard was performed by Xcel PRA personnel in 2006. This assessment compared the model containing the updated detailed internal flooding analysis and plant improvements to the Standard. This self-assessment identified several Supporting Requirements (SRs) that may be considered by a formal peer review to fall short of meeting Capability Category II. A majority of these SRs are specifically related to uncertainty analysis and documentation deficiencies would not directly impact the MELLLA+ quantification results. The other SRs that were identified are related to the use of shorter mission times (< 24 hours) for a limited number of components, human actions related to inducing and terminating internal flooding, and comparison of quantification results with similar plants. None of these items are expected to impact the conclusions of the MELLLA+ assessment. Any such changes would apply equally to both the MELLLA risk quantification and the MELLLA+ risk quantification and thus a non-significant impact to the delta risk estimates; as such, these have no impact on the conclusion of the MELLLA+ risk assessment.

The last comparison to the ASME standard was performed by Xcel personnel primarily to determine resource requirements anticipated to address gaps to Capability Category II of the standard in anticipation of a formal peer review. This self-assessment did not identify any items that were expected to impact the model in a significant and non-conservative direction, but were primarily directed toward enhancing documentation.

A.4 PRA QUALITY SUMMARY

The quality of modeling and documentation of the Monticello PRA models has been demonstrated by the foregoing discussions on the following aspects:

- Level of detail in PRA
- Maintenance of the PRA

- Comprehensive Critical Reviews

The Monticello Level 1 and Level 2 PRAs provide the necessary and sufficient scope and level of detail to allow the calculation of CDF and LERF changes due to MELLLA+.

Table A-3

PRA PEER REVIEW TECHNICAL ELEMENTS FOR LEVEL 1

PRA ELEMENT	CERTIFICATION SUB-ELEMENTS
Initiating Events	• Guidance Documents for Initiating Event Analysis • Groupings - Transient - LOCA - Support System/Special - ISLOCA - Break Outside Containment - Internal Floods • Subsumed Events • Data • Documentation
Accident Sequence Evaluation (Event Trees)	• Guidance on Development of Event Trees • Event Trees (Accident Scenario Evaluation) - Transients - SBO - LOCA - ATWS - Special - ISLOCA/BOC - Internal Floods • Success Criteria and Bases • Interface with EOPs/AOPs • Accident Sequence Plant Damage States • Documentation
Thermal Hydraulic Analysis	• Guidance Document • Best Estimate Calculations (e.g., MAAP) • Generic Assessments • FSAR • Room Heat Up Calculations • Documentation

Table A-3 (Continued)

PRA PEER REVIEW TECHNICAL ELEMENTS FOR LEVEL 1

PRA ELEMENT	CERTIFICATION SUB-ELEMENTS
System Analysis (Fault Trees)	• System Analysis Guidance Document(s) • System Models - Structure of models - Level of Detail - Success Criteria - Nomenclature - Data (see Data Input) - Dependencies (see Dependency Element) - Assumptions • Documentation of System Notebooks
Data Analysis	• Guidance • Component Failure Probabilities • System/Train Maintenance Unavailabilities • Common Cause Failure Probabilities • Unique Unavailabilities or Modeling Items - AC Recovery - Scram System - EDG Mission Time - Repair and Recovery Model - SORV - LOOP Given Transient - BOP Unavailability - Pipe Rupture Failure Probability • Documentation
Human Reliability Analysis	• Guidance • Pre-Initiator Human Actions - Identification - Analysis - Quantification • Post-Initiator Human Actions and Recovery - Identification - Analysis - Quantification • Dependence among Actions • Documentation

Table A-3 (Continued)

PRA PEER REVIEW TECHNICAL ELEMENTS FOR LEVEL 1

PRA ELEMENT	CERTIFICATION SUB-ELEMENTS
Dependencies	• Guidance Document on Dependency Treatment • Intersystem Dependencies • Treatment of Human Interactions (see also HRA) • Treatment of Common Cause • Treatment of Spatial Dependencies • Walkdown Results • Documentation

Structural Capability	• Guidance
	• RPV Capability (pressure and temperature)
	  - ATWS
	  - Transient
	• Containment (pressure and temperature)
	• Reactor Building
	• Pipe Overpressurization for ISLOCA
	• Documentation

Quantification/Results Interpretation	• Guidance • Computer Code • Simplified Model (e.g., cutset model usage) • Dominant Sequences/Cutsets • Non-Dominant Sequences/Cutsets • Recovery Analysis • Truncation • Uncertainty • Results Summary

Table A-4

PRA CERTIFICATION TECHNICAL ELEMENTS FOR LEVEL 2

PRA ELEMENT	CERTIFICATION SUB-ELEMENTS
Containment Performance Analysis	• Guidance Document • Success Criteria • L1/L2 Interface • Phenomena Considered • Important HEPs • Containment Capability Assessment • End state Definition • LERF Definition • CETs • Documentation

Table A-5

PRA CERTIFICATION TECHNICAL ELEMENTS
FOR MAINTENANCE AND UPDATE PROCESS

PRA ELEMENT	CERTIFICATION SUB-ELEMENTS
Maintenance and Update Process	• Guidance Document • Input - Monitoring and Collecting New Information • Model Control • PRA Maintenance and Update Process • Evaluation of Results • Re-evaluation of Past PRA Applications • Documentation

Appendix B

ROADMAP TO RS-001 REVIEW CRITERIA

Appendix B
ROADMAP TO RS-001 REVIEW CRITERIA

This appendix is provided to assist the reader or reviewer in locating key aspects and issues documented in this risk assessment.

The NRC Review Standard for Extended Power Uprates (RS-001) is used as the template for this MELLLA+ risk assessment roadmap.[16] Table B-1 lists risk assessment aspects contained in RS-001 and summarizes where in this MELLLA+ risk assessment report that aspect of the risk analysis is discussed.

Table B-1

ROADMAP TO RS-001 REVIEW CRITERIA

#	Risk Assessment Aspect	Treatment/Location in this Study
INTERNAL EVENTS RISK INFORMATION		
1	Impact on initiating event modeling and frequencies	No direct or significant impact on plant transient frequencies is indicated for MELLLA+; however, a quantitative sensitivity case is investigated in this study to determine the impact on the risk impact results if the frequency of transient initiators is conservatively postulated to increase due to the proposed changes. Data used in the MNGP PRA for estimating initiating event frequencies remains applicable to the MELLLA+ condition. No changes to other initiators due to MELLLA+ can be postulated. Refer to Sections 3.3.1, 4.1.1 and 5.7.1.
2	Impact on component/system reliability and response times	There are no hardware changes of note to the plant for MELLLA+; physical changes to the plant are limited to MCR displays and plant computer changes. No changes to system or component response times other than the faster response time for a instability trip due to use of CDA as the primary detection algorithm (refer to Section 3.3.1). This response time change has no impact on initiating event frequencies or PRA accident mitigation modeling. Refer to Section 3.4.1.
3	Impact on operator response times and associated error probabilities	MELLLA+ has the potential (given the initial plant power-to-flow configuration at the time of a postulated plant trip) to reduce available response times for operator actions during ATWS scenarios. Refer to Section 4.1.6.
4	Impact on functional and system level success criteria	MELLLA+ has just a single potential success criteria impact: license-based ODYN calculations show 8 of 8 SRVs required for RPV overpressure protection during ATWS scenarios with the RPV isolated from the main condenser (TRACG calculations show that 7 of 8 SRVs are sufficient). Refer to Section 4.1.2.

Table B-1

ROADMAP TO RS-001 REVIEW CRITERIA

#	Risk Assessment Aspect	Treatment/Location in this Study
5	Impact on PRA from other issues (e.g., procedure changes, maintenance practice changes, operational changes, setpoint changes)	No changes to the MNGP EOPs/SAMGs or Abnormal Operating Procedures are required for MELLLA+. Changes will be needed for all associated plant procedures, training documents, the process computer, Main Control Room (MCR) displays, and MCR Simulator related to the APRM setpoint changes. No impact on the risk profile results from such issues. Refer to Section 3.3.2. MELLLA+ does not involve any changes to maintenance practices that would impact the PRA. MELLLA+ requires setpoint changes related to the reactor power flow map and stability control. These changes remain within design limits. No reduction in design operating margins occurs due to these changes. No impact on the risk profile results from such setpoint changes. Refer to Section 3.3.3. Operation with the MELLLA+ expanded power-flow region has no direct impact on transient initiator frequencies, but a sensitivity case is quantified to assume an increase in transient initiator frequency. Refer to Sections 3.3.1 and 5.7.1.
6	Overall impact on CDF and LERF	Best estimate risk quantification results in delta CDF and delta LERF risk results in the RG 1.174 "very small risk increase" range. Refer to Executive Summary and Section 5.7.2. Section 5.7.1 discusses quantitative sensitivity cases.
7	Discussion of risk impacts on internal events risk profile	Refer to Sections 4.2 and 4.7 for impacts on the Level 1 and Level 2 PRA. Section 5.7.1 discusses quantitative sensitivity cases.
8	Scope, level of detail, and quality of PRA used in the analysis	The Monticello Level 1 and Level 2 PRAs provide the necessary and sufficient scope and level of detail to allow the calculation of CDF and LERF changes due to MELLLA+. Refer to Section 1.2 and Appendix A for discussion.

Table B-1

ROADMAP TO RS-001 REVIEW CRITERIA

#	Risk Assessment Aspect	Treatment/Location in this Study
9	Scope, level of detail and quality of thermal hydraulic analyses used in the analysis	No new PRA thermal hydraulic calculations are performed for the MELLLA+ risk assessment. The few thermal hydraulic calculations that are used in the MELLLA+ risk assessment are those documented in the MNGP MELLLA+ Task Reports (e.g., ODYN and TRACG calculations in TR 0902, ATWS); such thermal hydraulic analyses are of sufficient quality for both the licensing basis calculations as well as for use in the risk assessment calculations.
10	Processes for ensuring internal events PRA adequately models the as-built, as-operated plant	FP-PE-PRA-02, PRA Guideline for Model Maintenance and Update and PEI-05.01.03, PRA Guideline for Model Maintenance and Update, provide the processes and guidance for MNGP PRA model maintenance and periodic updates (refer to Appendix A.2).
11	Treatment of any vulnerabilities, weaknesses or review findings of the IPE Submittal	A summary of vulnerabilities, weaknesses and review findings from the IPE Submittal was performed in response to RAIs to the MNGP EPU LAR and is documented in Reference [19]. That summary is not reproduced here in this report. Those impacts have been previously incorporated into the MNGP PRA model where applicable.
12	Treatment of plant modifications or improvements credited in the IPE Submittal but not implemented in the plant	As documented in Reference [19], a review of the Monticello IPE and supporting documents was performed to determine if there were any modifications or improvements credited in the IPE/PRA but not yet implemented. The key engineers involved with the IPE development were also consulted to determine if there is any recollection of cases where modifications or improvements were credited in the IPE/PRA but not implemented at the time of the IPE submittal. No instances of credited, but not yet implemented capabilities were identified. The PRA model used for the MELLLA+ risk assessment does not credit any capability that will not be available or supported by approved procedures at the time of implementation of MELLLA+. The reference PRA model used for this analysis is the PRA model reflective of the plant configuration that will exist at the time of the MELLLA+ implementation. Refer to Section 1.2 and Appendix A for discussion.
13	Treatment of findings from any independent peer reviews	Refer to discussions in Appendix A.3.

Table B-1

ROADMAP TO RS-001 REVIEW CRITERIA

#	Risk Assessment Aspect	Treatment/Location in this Study
14	Justifications when risk impact exceeds RG 1.174 guidelines	The best estimate risk calculations do not exceed RG 1.174 guidelines. Refer to Section 5.7.2.
	EXTERNAL EVENTS RISK INFORMATION	
15	Treatment of any vulnerabilities, weaknesses or review findings of the IPEEE Submittal	A summary of vulnerabilities, weaknesses and review findings from the IPEEE Submittal was performed in response to RAIs to the MNGP EPU LAR and is documented in Reference [19]. That summary is not reproduced here in this report. No MNGP external events PRA models are quantified in support of this risk analysis. MELLLA+ has a non-significant impact on the external event risk profile. Refer to Sections 4.3 - 4.5 and 5.3 - 5.5.
16	Treatment of plant modifications or improvements credited in the IPEEE Submittal but not implemented in the plant	The PRA model used for the MELLLA+ risk assessment does not credit any capability that will not be available or supported by approved procedures at the time of implementation of MELLLA+. The reference PRA model used for this analysis is the PRA model reflective of the plant configuration that will exist at the time of the MELLLA+ implementation. Refer to Section 1.2 and Appendix A for discussion.
17	Discussion of risk impacts on external events risk profile	MELLLA+ has a non-significant impact on the external event risk profile. Refer to Sections 4.3 - 4.5 and 5.3 - 5.5.
18	Scope, level of detail, and quality of external events PRA models used in the analysis	No MNGP external events PRA models are quantified in support of this risk analysis. MELLLA+ has a non-significant impact on the external event risk profile. Refer to Sections 4.3 - 4.5 and 5.3 - 5.5.
19	Processes for ensuring external events PRA models used in the analysis adequately reflect the as-built, as-operated plant	No MNGP external events PRA models are quantified in support of this risk analysis. MELLLA+ has a non-significant impact on the external event risk profile. Refer to Sections 4.3 - 4.5 and 5.3 - 5.5.
	SHUTDOWN RISK INFORMATION	
20	Impact on shutdown initiating events	MELLLA+ has no impact on initiating events that apply to shutdown conditions. Refer to Section 4.6.
21	Impact on component/system reliability and response times	MELLLA+ has no impact on the reliability, availability or response times of components and systems used during shutdown conditions. Refer to Section 4.6.

Table B-1

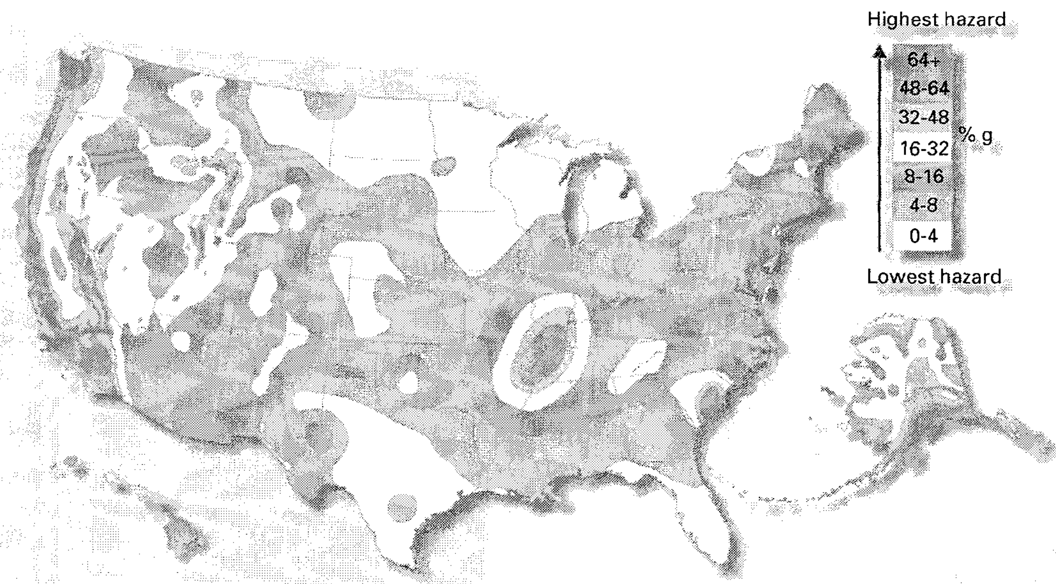
ROADMAP TO RS-001 REVIEW CRITERIA

#	Risk Assessment Aspect	Treatment/Location in this Study
22	Impact on operator response times and associated error probabilities	MELLLA+ has no impact on operator response times and associated error probabilities for operator actions that may be required during shutdown conditions. Refer to Section 4.6.
23	Impact on functional and system level success criteria	MELLLA+ has no impact on the success criteria for functions an systems used during shutdown conditions. Refer to Section 4.6.
24	Impact on shutdown risk from other issues (e.g., procedure changes, maintenance practice changes, operational changes, setpoint changes)	MELLLA+ has no impact on shutdown operations or the shutdown risk profile. Refer to Section 4.6.
25	Discussion of risk impacts on shutdown risk profile	MELLLA+ has no impact on shutdown operations or the shutdown risk profile. Refer to Section 4.6.
26	Discussion of shutdown risk management philosophies, processes, and controls	MELLLA+ has no impact on shutdown operations or the shutdown risk profile. Refer to Section 4.6.

Exhibit G-1

2008 United States National Seismic Hazard Maps

The U.S. Geological Survey's National Seismic Hazard Maps are the basis for seismic design provisions of building codes, insurance rate structures, earthquake loss studies, retrofit priorities, and land-use planning. Incorporating these hazard maps into designs of buildings, bridges, highways, and critical infrastructure allows these structures to withstand earthquake shaking without collapse. Properly engineered designs not only save lives, but also reduce disruption to critical activities following a damaging event. By estimating the likely shaking for a given area, the maps also help engineers avoid costs from over-design for unlikely levels of ground motion.



*Colors on this map show the levels of horizontal shaking that have a 2-in-100 chance of being exceeded in a 50-year period. Shaking is expressed as a percentage of **g** (**g** is the acceleration of a falling object due to gravity).*

The Update Process

The U.S. Geological Survey recently updated the National Seismic Hazard Maps by incorporating new seismic, geologic, and geodetic information on earthquake rates and associated ground shaking. These 2008 maps supersede versions released in 1996 and 2002. Updating the maps involved interactions with hundreds of scientists and engineers at regional and topical workshops. USGS also solicited advice from working groups, expert panels, State geological surveys, Federal agencies, and hazard experts from industry and academia. The Pacific Earthquake Engineering Research Center developed new crustal ground-motion models; the Working Group on California Earthquake Probabilities revised the California earthquake rate model; the Western States Seismic Policy Council submitted recommendations for the Intermountain West; and three expert panels were assembled to provide advice on best available science.

Changes to the Maps

The most significant changes to the 2008 maps fall into two categories, as follows:

1. Changes to earthquake source and occurrence rate models:
   - In California, the source model was updated to account for new scientific information on faults. For example, models for the southern San Andreas Fault System were modified to incorporate new geologic data. The source model was also modified to better match the historical rate of magnitude 6.5 to 7 earthquakes.
   - The Cascadia Subduction Zone lying offshore of northern California, Oregon, and Washington was modeled using a distribution of large earthquakes between magnitude 8 and 9. Additional weight was given to the possibility for a catastrophic magnitude 9 earthquake that ruptures, on average, every 500 years from northern California to Washington, compared to a model that allows for smaller ruptures.

- The Wasatch fault in Utah was modeled to include the possibility of rupture from magnitude 7.4 earthquakes on the fault.
- Fault steepness estimates were modified based on global observations of normal faults.
- Several new faults were included or revised in the Pacific Northwest, California, and the Intermountain West regions.
- The New Madrid Seismic Zone in the Central U.S. was revised to include updated fault geometry and earthquake information. In addition, the model was adjusted to include the possibility of several large earthquakes taking place within a few years or less, similar to the earthquake sequence of 1811–1812.
- Source models for the region near Charleston, S.C., have been modified to include offshore faults that are thought to be capable of generating earthquakes.
- A broader range of earthquake magnitudes was used for the Central and Eastern U.S.
- Earthquake catalogs and seismicity parameters were updated.

2. Changes to models of ground shaking (that show how ground motion decays with distance from an earthquake's source) for different parts of the U.S., based on new published studies:
   - New ground-motion prediction models developed by the Pacific Earthquake Engineering Research Center were adopted for crustal earthquakes beneath the Western U.S. These new models use shaking records from 173 global shallow crustal earthquakes to better constrain ground motion in western States.
   - Several new and updated ground-shaking models for earthquakes in the Central and Eastern U.S. were implemented in the maps. One of the new ground-shaking models accounts for the possibility that ground motion decays more rapidly from the earthquake source than was previously considered.
   - New ground-motion models were applied for earthquake sources along the Cascadia Subduction Zone.

Significance of Results

The new National Seismic Hazard Maps show, with some exceptions, similar or lower ground motion compared with the 2002 edition. For example, ground motion in the Central and Eastern U.S. has been generally lower by about 10–25 percent due to the modifications of the ground-motion models. Ground motion in the Western U.S. is as much as 30 percent lower for shaking caused by long-period (1-second) seismic waves, which affect taller multistory buildings, and ground motion is similar (within 10–20 percent) for shaking caused by short-period (0.2-second) waves, which affect structures of one or a few stories.

The new 2008 maps represent the best available science as determined by the USGS from an extensive information-gathering and review process. Changes will be made in future versions of the maps as new information on earthquake sources and resulting ground motion is gathered and processed.

San Francisco, Calif., Earthquake, April 18, 1906. Fault trace 2 miles north of the Skinner Ranch at Olema. View is north. 1906. Plate 10, U.S. Geological Survey Folio 193; Plate 3-A, U.S. Geological Survey Bulletin 324. (USGS Photo Library). Photograph by G.K. Gilbert.

For Further Information

To learn more about the National Seismic Hazard Mapping Project, go to URL *http://earthquake.usgs.gov/hazmaps/*;
Working Group on California Earthquake Probabilities, go to URL *http://pubs.usgs.gov/of/2007/1437/*
Or you may also contact Mark Petersen: mpetersen@usgs.gov.

Exhibit G-2

Earthquake Hazards Program

Historic Earthquakes

Western Minnesota
1975 07 09 14:54:15 UTC
Magnitude 4.6
Intensity VI

Largest Earthquake in Minnesota

The earthquake caused minor damage to walls and foundations of basements in Stevens County around Morris. Also felt in Iowa, North Dakota, and South Dakota.

The earthquake was felt over an area of approximately 315,000 square kilometers including northern Iowa, Minnesota, southeastern North Dakota, and eastern South Dakota. Maximum intensity was VI. This is the largest earthquake ever instrumentally located in the state of Minnesota. The last strongly felt earthquake in the State was a shock that occurred on September 3, 1917 near Staples with a maximum intensity of VI.

Abridged from Seismicity of the United States, 1568-1989 (Revised), by Carl W. Stover and Jerry L. Coffman, U.S. Geological Survey Professional Paper 1527, United States Government Printing Office, Washington: 1993, and Earthquake Information Bulletin, Volume 7, Number 5.

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